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© CANADA'S NATIONAL OIL POLICY AND THE OUTLOOK FOR THE FUTURE

by

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies for acceptance a thesis entitled Canada's National Oil Policy and the Outlook for the Future, submitted by William J. Henderson in partial fulfilment of the requirements for the degree of Master of Arts.

ABSTRACT

In February of 1961 the government of Canada implemented a National Oil Policy that rescued the Canadian petroleum industry from dire straits. The history of the National Oil Policy has been one of varied degrees of success. However, at present the National Oil Policy is facing its sternest crisis.

The market outlook for Canadian crude petroleum is examined and the conclusion drawn is that if markets are to be expanded on the basis of economic considerations, some reduction in the price of Canadian crude must occur. Therefore, the scope for wellhead price reductions in both conventional and synthetic crude production is analyzed and it is found that wellhead prices could be lowered considerably. With this in mind, an attempt is made to draw some guidelines for the future.

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CHAPTER I

THE DEVELOPMENT OF THE CANADIAN OIL INDUSTRY

Introduction

Although the presence of oil in Canada has been known for more than a century, Canada's petroleum industry did not achieve any degree of significance until the discovery of large crude reserves at Leduc in 1947. In 1946, Canada produced 7,586,000 barrels of crude oil, less than ten per cent of her crude requirements. Expansion of the industry raged from 1947 until restoration of order in the Middle East in 1957. Then, Canada's daily crude production averaged 501,000 b/d, sufficient to supply 67 per cent of her crude requirements.[1]

As production expanded after the Leduc discovery, prairie oil began to flow across the prairie region, displacing higher cost American crude and product imports. In 1949, because Alberta reserves were capable of producing (under accepted conservation principles) at rates in excess of demand, a market proration plan was implemented in Alberta. Later discoveries

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[1]Figures from The Canadian Petroleum Industry, (Toronto Dominion Bank, 1968), p. 21, and "Demand to Hit 1.25 Million B/d," *Oilweek* (February 20, 1967), p. 94.

of additional fields near Edmonton necessitated the opening up of new market areas for Canadian crude. In order to reach Ontario, the nearest substantial Canadian market to the east, the Inter-provincial Pipeline Company constructed a large diameter pipeline from Edmonton to Superior Wisconsin, a distance of 1129 miles at a cost of about $90 million. Initially, western Canadian crude was shipped from Superior to Sarnia, with the Imperial Leduc landing the first shipment at Sarnia on April 24, 1951.[2] Extensive storage capacity enabled the system to overcome the handicap of the seven month navigation season on the Great Lakes. However, by 1953, the increasing Ontario demand for crude plus the greater economy of pipeline transportation as compared with tanker and winter storage, resulted in the extension of the line from Superior to Sarnia. In 1957, the line reached Toronto, laying down Canadian crude competitively with U.S. crude.

Simultaneously, attention was focused on the possibility of constructing a crude oil line westward from Alberta to the Pacific Coast. However, the B.C. market alone (40,000 b/d in

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[2] Eric J. Hanson, Dynamic Decade, (Toronto: McClelland and Stewart Ltd., 1958), p. 158.

1951)[3] was inadequate to warrant a $10 million pipeline project. Potential markets existed in the U.S. Puget Sound area, which at the time, unfortunately, lacked refinery capacity, despite a daily demand of around 200,000 barrels.[4] The outbreak of the Korean war which underlined the vulnerability of refineries dependent on overseas crude, the relatively slow growth of California reserves in relation to demand, and the continued growth of the Alberta oil industry enabled Canadians to obtain financial backing for the Trans Mountain pipeline from U.S. oil companies interested in the construction of refinery capacity in the Puget Sound area. A 718 mile line, the first designed primarily to deliver Canadian crude to export markets, was completed in 1953, with subsequent extensions to Ferndale and Anacortes, Washington in 1954 and 1955. Table 1 illustrates the growth of refinery capacity in this market in response to a secure supply of Canadian petroleum.

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[3] Ibid., p. 160.

[4] Alan R. Plotnick, Petroleum, Canadian Markets and United States Foreign Trade Policy, (Seattle: University of Washington Press, 1964), p. 59.

Table 1 - Rated Refinery Capacity in Washington State and British Columbia

Location	1954	1956	1958
B.C.	32,000 b/d	75,500	96,750
Washington State	- - - - -	85,000	104,000
	32,000	160,500	200,750

Source: Oil and Gas Conservation Board of Alberta, cited in Plotnick, op. cit. p. 69.

This was the first substantial American influence on the marketing of Canadian crude, and served as a cornerstone for an unyielding pattern of profound influence on the development of the Canadian petroleum industry.

Successful oil play in Alberta spurred on activity across the prairies. In Saskatchewan, initial attention centered on the Lloydminster area, but in 1954, crude was discovered in the south-eastern areas of the province. With the discovery of crude in the Virden area of Manitoba in 1951 and in northern British Columbia in 1956, all of western Canada was involved in the production of crude.

The year 1956 marked a high point in the Canadian petroleum industry. Table 2 illustrates the progress achieved

in Canada's first petroleum decade.

Table 2 - Indicators of Growth in the Canadian Oil Industry

	1946	1951	1956
Geophysical parties (Western Canada) Maximum number during year	11	155	149
Exploration, development, and producing expenditures (Western Canada) million $	22	246	612
Well count (Western Canada) capable of producing at year end	520	3034	10587
Reserves at year end (crude and NGL's million of barrels	72	1376	3129
Production-crude and NGL's Thousand b/d	19	133	476
Refinery capacity at year end Thousand b/d	246	421	700
Capital investment in the petroleum and natural gas industry (million $)	55.2	158.6	707.9
% self sufficient	8*	31	65

* 1947 figure

Source: Canadian Petroleum Industry, Achievements and Prospects, (Toronto Dominion Bank, 1968), p. 29 and "Demand to Hit 1.25 Million B/d," Oilweek (February 20, 1967), p. 94.

Growth of Export Markets

Since transportation and refinery are complementary operations, Alberta crude began to supply several American mid-west refineries along the path of the Interprovincial pipeline. In addition, with the discovery of medium gravity high sulphur content crude (which was ill-suited for refineries in both the U.S. Great Lakes Area and Canada) the U.S. Minnesota market was tapped. By the end of 1956, Manitoba crude had entered the Minnesota area and south-eastern Saskatchewan crude had been delivered to the Interprovincial System. Table 3 outlines the growth of crude oil exports to these markets.

Table 3 - Canadian Crude Oil Exports to U.S. Mid-West Refinery Market (thousands of barrels per day)

Province	1955	1956	1957	1958
Alberta	9	30	17	13
Saskatchewan	7	19	32	39
Manitoba	-	1	8	8
	16	50	57	60

Source: Plotnick, op. cit., p. 63.

The Pacific Northwest market continued to expand, and by 1956, due primarily to the Suez crisis,[5] approximated the refinery capacity of the area. The following year, during the height of the crisis, the Trans Mountain pipeline was operated at its full capacity of 200,000 b/d.

In anticipation of the crisis, tanker rates spiralled, ultimately reaching USMC plus 125, whereas as recently as 1955, they had been as low USMC minus 30.[6] This resulted in Alberta crude becoming competitive for the first time in California. January 1, 1956 saw the first tanker loaded for San Francisco. Such shipments averaged 16,929 b/d in 1956, and 19,579 b/d in 1957. In May of 1957 offshore exports peaked at 59,324 b/d; for 1957, average daily exports to the west coast were 93,478.[7]

As the Suez crisis passed, foreign crudes, much to the chagrin of Canadian producers, reclaimed their dominant position

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[5]The Suez Canal was nationalized by Egypt on July 26, 1956. Following the outbreak of fighting in October, the canal was closed to traffic until the summer of 1957.

[6]Canada, Royal Commission on Energy, Second Report to His Excellency the Governor General in Council, (July, 1959), p. 32. USMC plus 125 would be 125 percent above the ceiling rates enforced by the United States Maritime Commission in World

in the world petroleum trade. In 1957, Canadian exports of crude and unfinished products to the U.S. dropped from 173,000 b/d in the second quarter to 138,000 b/d in the third quarter and to 119,000 b/d in the fourth quarter, ultimately reaching a minimum of 66,000 b/d in the fourth quarter of 1958. The fall in Canadian exports occurred entirely on the west coast. From a high of 135,662 b/d in May 1957, daily exports to this area fell to 10,002 b/d in December, 1958. By October, 1957, offshore exports had ceased completely.

Habitually, three theses are expounded as explanations for this abrupt change in trade patterns. The first, and most obvious, was the waning of the Suez crisis. One of the chief factors was the dramatic increase in tanker tonnage available resulting from both new tanker construction and the return to service of old tankers in an attempt to overcome the Suez crisis.

War II for U.S. government tanker commitments. The USMC rates were established for each of the major supply routes. No longer of any official significance, they serve as a standard of reference against which the prevailing market level could be measured and expressed.

[7] *Ibid.*

In addition, the crisis spurred the development of super tankers. With the re-opening of the canal, the fall in exports was not unexpected, but the sheer magnitude of the fall intimated that the return to normal oil trade was not the sole causal factor. Exports in the first and second quarters of 1958 were below the same quarters for 1956, and exports in the fourth quarter of 1958 were below those of the fourth quarter of 1955. Both the 1955 and 1956 quarters were unaffected by the Suez crisis.[8]

A second explanation is based on the general business recession in the United States. Plotnick identified the period as follows:

> The pre-recession peak in the United States occurred in August, 1957, with the recession taking place (the trough itself) in April 1958. These two dates correspond with the high and low months during 1957-58 for the United States index of industrial production. Canada's over-all total of merchandise exports to the United States showed a decline during 1957 which reached a trough in April 1958, and then began a gradual recovery. An examination of the series for Canada's merchandise exports to the United States and the

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[8] Edward H. Shaffer, The Oil Import Program of the United States, An Evaluation, (New York: Frederick A. Praeger, 1968), p. 120.

United States index of industrial production during the period of difficulty in the Canadian petroleum export market shows a simultaneous decline in both economic movements.[9]

The business indicators presented in Table 4 show that Canada too experienced a recession

Table 4 - Canadian Business Indicators by Quarters 1957 % Increase or Decrease Over Similar Period 1956

	first	second	third	fourth
Index of industrial production	4.9	1.5	-1.5	-4.9
Durable goods	4.8	-4.1	-8.0	-10.3
Steel	7.2	-2.0	-4.7	-19.9
Railway (carloadings)	-5.6	-9.9	-8.3	-9.2
Motor Vehicles	18.9	-19.4	-18.5	-29.6
Newsprint	3.8	3.4	-1.3	-10.1
Lumber	-14.1	-6.0	-13.8	-15.3
Crude Production	15.0	27.8	3.3	-16.7

Source: Imperial Oil, Submission to Royal Commission on Energy, (May, 1958), p. 21.

[9] Alan R. Plotnick, op. cit., p. 77.

Further complicating the Canadian situation was the inappropriate monetary policy pursued in the late 1950's. The recession did lead to a decline for petroleum products in the U.S., resulting in large inventories throughout the industry. As refineries reduced crude runs and drew upon inventories, Canadian exports fell. However, the recession cannot explain the decline in the Canadian share of the U.S. market. In the first quarter of 1958 Canadian share was 11.7 per cent, almost two percentage points below its share in the first quarter of 1956. Similarly, in the fourth quarter of 1958, its share was 6.6 per cent while in the fourth quarter of 1955 it was 9.1 per cent.[10]

The third and least satisfactory explanation was that changes in the U.S. quota system resulted in decreased exports. To analyze this argument requires some background information on the 1957 alterations in American import control policy. In early February 1955, a special Cabinet committee of the President had reported that for interests of national security, imports of crude and other oil should be maintained in the same ratio of imports to domestic production that existed in 1954. This meant imports would have been limited to around 700,000 b/d. For security reasons,

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[10]Edward H. Shaffer, op. cit., p. 120.

however, Canadian and Venezuelan imports would be exempted. In 1956, the government requested U.S. refiners to reduce their purchases, but the ensuing Suez crisis postponed any government action. After the Suez crisis, larger quantities of foreign oil began to enter the U.S. market, which at that time was quite depressed. Thus, on July 29, 1957, a voluntary import control program with allocations based on past import performance was adopted. The quotas were 756,000 b/d in Districts I-IV (i.e., east of the Rocky Mountains) and 275,000 b/d for District V (Alaska, Arizona, California, Hawaii, Nevada, Oregon, and Washington.) The plan was altered in December of the same year because demand in District V had declined significantly due to general economic conditions and natural gas competition. The new quota was 220,000 b/d.

It should be noted that the Canadian quotas were not filled. By the end of 1958, Shell's Anacortes, Washington refinery was operating 100 per cent on Californian crude. Thus, General Petroleum, a Socony subsidiary, was left as the sole west coast importer of Canadian crude. Its imports of 10,000 b/d were only due to a "swap" arrangement whereby Imperial Oil accepted Socony's Venezuelan crude at its eastern Canadian refineries in return for the right to export Canadian crude to Socony's

Pacific coast facilities. Yet, at this juncture, the voluntary oil import program seemed about to collapse due to the large number of U.S. firms involved in the import trade. The problem was twofold. Firstly, some companies were unwilling to abide by the voluntary program and, secondly, others were expected to refuse reductions in their allocations to allow newcomers import priveleges. This resulted in a mandatory program with no exemptions being implemented on March 10, 1959. For Canada, the most important alteration (on paper) was a reduction in the District V quota from 73,600 b/d to 58,880 b/d. But, as mentioned above, at this time only one refiner was importing Canadian crude into this area. Furthermore, when Texaco's new Anacortes refinery finally did utilize Canadian crude, its imports comprised less than one-half of its quota. The District I-IV quota was officially 3,400 b/d, but, like the District V situation, the quotas were not fully utilized, thus purchases from Canada were not affected.

Quirin[11] offers some evidence supporting the hypothesis that import quotas could have adversely affected Canadian sales in the U.S. He assumed a refiner with a refinery capacity of 100,000 b/d in Washington and 1,000,000 b/d in California with the following price structure.

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[11] Dave Quirin, forth coming, Chapter 6, p. 32.

Source	California	Washington
U.S.	X	X + .25
Canada	X + .10	X - .25
Overseas	X - .35	X - .35

Under a quota of 300,000 b/d, and with Canadian crude exempt, cost minimization would result in the utilization of the entire foreign crude quota in California, with the use of Canadian crude in his Washington refinery. With a quota of 400,000 b/d, <u>including</u> Canadian imports, which would no longer be exempt, costs would be minimized by the use of overseas crude to the full extent of the quota.

Calif. refinery	unit cost	exempt system	increased quota
U.S. Crude	X	700,000 X	700,000 X
Overseas	X - .35	300,000 X -105,000	300,000 X -105,000
Washington refinery			
U.S.	X + .25	-	-
Canada	X - .25	100,000X -25,000	-
Overseas	X - .35		100,000X - 35,000
		1,100,000X-130,000	1,100,000X-140,000

In refutation, consider the temporary upward trend in exports that started in January 1959, in the midst of the quota system. The statistics alone would say the quotas caused a 200 per cent increase

in this period. Similar illogical reasoning could explain the 75 per cent increase of May exports over April exports during the period of mandatory controls.[12] Furthermore, how would Quirin's reasoning explain the drop of exports following the Canadian exemption to levels below those recorded earlier in the year.

What gravitates from this discussion is the extent to which the marketing policies of the integrated companies could affect Canada's trade. At the termination of the Mid-East crisis, Canadian oil was competitive with Californian, Mid-Eastern and Venezuelan crude in the North-West United States.

Table 5 -Competitive Position of Canadian Crude in Puget Sound Market (May, 1958)

Source	Total Laid Down Cost
Redwater (35°)	3.29
Sumatra (34°)	3.27
Kuwait (31°)	3.31
Arabia (34°)	3.49
Venezuela (34°)	3.77
California (35°)	3.85

Source: A Plotnick, op. cit., p. 80.

It is interesting to note that the 1959 mandatory policy as

[12] Editorial, Oil in Canada (August 17, 1959), p. 7.

announced on March 10 was coincident with the desires of the cartel companies, who did not wish American refineries to have access to Canadian crude. While the increase in Canadian imports was large in absolute terms, our share in total U.S. imports was still small, 9 per cent, compared to Venezuela's 48 per cent and the mid-east's 35 per cent.[13] The change in policy becomes more puzzling when it is realized that the increase in Canadian crude imports resulted in a supply pattern more in line with the national security objective of the import policy. Other company marketing considerations could explain the drastic change in Canada's exports. Firstly, an inventory surplus had developed in the San Francisco area. Secondly, because of well established relationships with local producers west coast refiners opted to use their crude. Finally there was a reluctance on the part of the integrated companies, to use pro-rated Canadian crude in place of wholly owned foreign crude. "Although three of the internationals, Gulf, Socony, and Texaco . . . . owned both reserves in Canada and refineries with pipeline connections to the Interprovincial Lakehead pipeline they did not bring any Canadian crude into them during the U.S. voluntary

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[13] Edward H. Shaffer, op. cit., p. 115.

import program."[14]

In summary, the export decline had grave effects for the Canadian oil industry. Alberta, with the greatest capacity, and then the sole province with pro-rationing, was particularly hard hit. While production in other provinces increased in 1957, Alberta's output fell for the first time since Leduc, and in 1958 reached a level below that of 1955,[15] with production less than one-third its capacity.[16] Table 6 presents further indication of the state of despair of the Canadian petroleum industry.

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[14] Ibid., p. 117

[15] Editorial, Oil in Canada (Aug. 17, 1959), p. 7.

[16] John Davis, Oil and Canada - United States Relations, (Canadian-American Committee 1959), p. 13.

Table 6 - Indicators of the State of the Petroleum Industry

	1957	1958	1959
Geophysical parties W. Can. - crews months during the year	1547	1320	968
Exploration & Development ($ million)	622	592	602
New Field wildcats (1)	805	650	768
Other exploratory (2)	401	316	299
Development wells (3)	2238	1916	1821
Total (1,2,3)	3444	2882	2888
Total cash expenditure	$622,000,000	592,200,000	601,700,000
Royalties	492,000,000	273,800,000	294,300,000
Production as per cent of capacity	50%	48%	53%

Source: The Canadian Petroleum Industry - Achievements and Prospects, (Toronto-Dominion Bank, 1968), p. 29, Canadian Petroleum Association Year Book, 1966, P. 42, and Oilweek (February 21, 1966), p. 64.

The oil industry was at a crucial point in its history. While production remained relatively constant in the 1957-59 interval, reserves continued to grow. For the first time in the post-Leduc era, both the reserves production ratio and the reserves life index rose, the former to 21.1 from 18.1 in 1957, the latter

to 21.4 years from 17.7 years in 1957.[17] These figures represent but a part of the world surplus of petroleum evident at the time, due primarily to discoveries of vast reserves in Venezuela and the Middle and Far East. Contributing to the excess supply problem were the Alberta leasing and prorationing system which, despite the world excess supply, induced operators to increase productive capacity. The emergence of natural gas as a strong competitor to oil in both domestic and industrial heating markets worsened the situation. Hardest hit in Canada were the non-integrated companies who earnestly agitated for the construction of pipeline facilities to move Canadian crude into the Montreal market. In addition these companies feared that foreign crude would be laid down competitively in the Ontario market and "give refineries located in Montreal and using foreign crude a significant competitive advantage in most of the densely populated parts of the Ontario products market, to which they had access via the Trans-Northern products pipeline."[18]

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[17] "Consumption Matches '69 Growth," Oilweek (April 20, 1970), p. 42, and "Billion Barrel Gain for 1965?" Oilweek (February 21, 1966), p. 64.

[18] Dave Quirin, op. cit., Chapter 6, p. 18.

The Royal Commission on Energy (Borden Commission)

By an Order in Council dated the 15th of October 1957, the Diefenbaker government had established a Royal Commission on Energy to study Canada's energy resources with the purpose of ascertaining the most "effective use of those resources in the public interest".[19] As the Commission's hearings progressed, considerable testimony involved the substitution of domestic for foreign crude in the Montreal refinery market. Although this issue was not specifically included in the terms of reference to the Commission, it judiciously realized the impossibility of separating the inter-related problems of domestic and export markets for Canadian crude. Thus, the Second Report of the Commission, issued in July 1959, dealt broadly with the problems of the Canadian petroleum industry, and more specifically with the Montreal market issue.

The discussions focused on the fact that a country with reserves approaching 4,000 billion barrels and producing at less than 46 per cent of capacity was only 62 per cent self-sufficient (net) in petroleum[20], while its largest single market, the

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[19] Canada, Royal Commission on Energy, First Report to His Excellency the Governor General in Council, (October, 1958), p. 90.

[20] "Consumption Matches '69 Growth," Oilweek (April 20, 1970), p. 46, and "Billion Barrel Gain for 1965?" Oilweek (February 21, 1966), p. 64.

Montreal refining complex, was served entirely by foreign crude, primarily Venezuelan. For various reasons, Canadian oil is expensive in relation to Venezuelan and Mid-Eastern crude. In the first place, exploration, development, production and replacement costs are higher. These factors, coupled with huge reserves, allowed water-borne crude to yield higher profits since a minimal portion of earnings have to be re-invested to replenish reserves.[21] In addition the major integrated oil companies own foreign supplies but with prorationing in Alberta, they must purchase crude produced by other companies as well as crude from their own wells. It is not unlikely such purchases could benefit their competitors more than themselves.[22] Thus lower costs together with more lucrative intra-company transactions led the cartel companies to import

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[21]The September 4, 1959 issue of Oilweek (p. 17) provides some interesting comparisons. At that time, Canada was using her reserves at a rate of 5 per cent /yr. versus 1 per cent for the Middle East. The finding developing and production costs for the Middle East, Venezuela and Canada per barrel were respectively 30¢, 75¢ and $1.00 plus.

[22]The economic basis of this statement is the fact that, generally, a dollar of before-tax profit in production yields a greater after-tax profit than a dollar of before-tax profit in refining.

foreign crude for use in the Montreal market.[23]

As a result of its direct access to water-borne crude, Montreal had developed into Canada's largest refining centre, despite the fact that the largest Eastern Canada market for refined products was centered in Ontario. Two pipelines further entrenched this ironic situation. The 236 mile Portland-Montreal line which enabled Montreal to overcome the handicap of port closure demanded by winter, was supplying some 253,000 b/d by the end of 1958. On the other hand, Montreal manufactured products reached the Toronto-Hamilton area - the heart of the Ontario market - via the Trans-Northern products pipeline.

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[23]At that time, all of the Montreal refineries were controlled, at least in part, by international oil companies - Imperial Oil Limited by Standard Oil of New Jersey, B.A. Oil Co. Ltd. by the Gulf Corporation, Shell Oil of Canada Ltd. by the Royal Dutch Shell Group, Texaco Canada Ltd. by Texaco Inc., Canadian Petroleum Ltd. by Petrofina S.A., and British Petroleum Refinery Canada Ltd. by the British Petroleum group. All of these companies owned or had access to substantial foreign reserves. In 1957, five of these refiners also owned substantial reserves in Western Canada and controlled 80 per cent of Canada's refining capacity.

Table 7 - Refinery Capacity and Petroleum Product Demand in Eastern Canada (1958)

Province	% of E. Can. Refinery Capacity	Petroleum Products Demand
Ontario	42.1	49.7
Quebec	48.8	37.2
Atlantic Provinces	9.1	13.1

Source: Canada, Royal Commission on Energy, Second Report to His Excellency, the Governor General in Council (July, 1959), p. 91.

Thus the governments of the producing provinces and some segments of the petroleum industry came to regard the Montreal market as the panacea for the slumping Canadian petroleum industry, Yet, the notion of domestic crude in Montreal produced strongly divergent opinions within the Canadian petroleum industry. The major companies who had already tied their Montreal refineries to foreign crude, opposed the independents, who, unlike the majors had no such commitments. The latter group pointed out that Canada was probably the only country in the world with shut-in capacity that was a net importer of crude. In an appeal to public sentiment they mentioned the balance of payments savings of access to the Montreal market, while the majors retorted with the economic impractibility of such a move.

The entire issue hinged upon the construction of pipeline facilities to the Montreal area, and three such proposals were heard by the Commission. The first submission, prepared by

Canadian Bechtel at the Commission's request, considered two basic pipeline systems, a new direct line and an expanded Interprovincial Pipeline system. Cost data for the various alternative routes is given in Table 8.

Table 8 - Cost Data (1959), Alternative Edmonton-Montreal Pipelines. Cost/bl. of Transportation

	Distance	Cost/bl. of Transportation
Expanded I.P. System	2245	69.1¢
All Canadian Route	2100	83.9¢
Via Sault Ste. Marie	2060	73.9¢
Parallel to I.P. System	2245	78.8¢

Source: Canada, Second Report, p. 104.

An extension of the Interprovincial system involving a capital expenditure of $299,022,000 would yield a tariff of 69.1¢/bl. based on a 255,000 b/d throughput, whereas a new $345 million thirty inch line via Sault Ste. Marie would require a first year tariff of 73.9¢/bl. Edmonton to Montreal. Design capacity of the latter would be 300,000 b/d in order to provide for expansion of throughput. The Bechtel submission reached the following conclusions:

(1) From an engineering standpoint there are no insurmountable problems involved in the construc-

tion or operation of an oil pipeline from Edmonton to Montreal.

(2) If an entirely new pipeline system is to be built, the most economic route parallels the Interprovincial line to Superior and thence goes eastward through Sault Ste. Marie directly to Montreal.

(3) For the movement of average daily volumes of crude oil up to 300,000 barrels, transportation by an expanded Interprovincial system has an economic advantage over a new direct pipeline system. Based on the conditions and assumptions outlined in the report at an average daily volume of 255,000 barrels, the cost of transportation in a new direct pipeline will be 73.9 cents per barrel and 69.1 cents per barrel through the expanded Interprovincial system. At lesser volumes, the economic advantage would be greater.

(4) Construction of an entirely new pipeline system would in our opinion require two construction seasons for completion.[24]

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[24]Canadian Bechtel, Submission to the Royal Commission on Energy, (July, 1958), p. 17.

The second submission was presented by the Independent Pipeline Company which acted as a spokesman for the large number of independent companies referred to as the Home Oil group. Their final proposal envisioned a combined thirty-four and thirty-six inch line with initial throughput of 224,000 b/d, rising to 402,000 b/d by 1970. Construction costs were estimated to be $37 million, service costs 72.7¢ the first year, dropping to 48.1¢ in the fourth year. A more general submission was presented by Interprovincial Pipeline Company which felt it could expand within one year to provide 200,000 b/d to the Montreal market at rates comparable to those of any other system utilizing equal volume, throughput, and rates of return. Canadian Bechtel was also commissioned to study whether a publicly-owned line could lay down Canadian crude in Montreal without an increase in consumer prices. The engineering company discovered that a thirty inch line would cost $380 million for initial capacity of 200,000 b/d which could be increased to 300,000 b/d. Such a line, moreover, would have to follow an all Canadian route as a matter of public policy. A tariff of 49¢/bl. would suffice to cover direct operating costs, interest and depreciation provided income tax could be omitted and two per cent depreciation applied.

The two major submissions differed on two significant

points. Canadian Bechtel based its estimates on funded debt of 75 per cent, 10 per cent less than the 85 per cent assumed by the Home Oil group. Secondly, the former assumed a rate of return before payment of interest of 8.75 per cent versus the 4.75 per cent postulated by the latter. In all fairness the finance question could not have been settled until an adequate foothold was obtained in the Montreal market. The independents believed the only guarantee necessary was a promise by Montral refiners to purchase 200,000 b/d from 1960, and 320,000 b/d in 1965.[25] The viewpoint of the majors was that the venture was so risky that greater government control of the industry in the form of a guarantee of pipeline bonds and a protective tariff would be required to finance the line. Underlying the view was the majors' belief that Canadian crude could not be competitive with foreign crude in the Montreal market.

Data presented to the Commission by the majors supported this contention.

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[25] Alan R. Plotnick, op. cit., p. 51.

Table 9 - Estimated Laid-Down Costs for Canadian and Imported Crude Oil at Montreal 1961, (Canadian and U.S. Currencies at Par).

Crude Source	Well Lead Price	Total Laid-Down Cost	Redwater Disadvantage
Redwater (35°)	\$2.72	\$3.50	- - -
Kuwait (31°)	\$1.85	\$3.05	\$0.45
Arabian (34°)	\$2.08	\$3.23	\$0.27
Venezuelan-Mesa (31°)	\$2.86	\$3.24	\$0.26

Source: adapted from British American Oil Company Ltd., Submission to the Royal Commission on Energy, (May, 1958), p. 20.

Canadian Bechtel estimated Canadian crude would have been at a disadvantage of 25-35¢/bl, whereas under the Independent Pipeline Company, the disadvantage was estimated to be 5-15¢/bl.[26] These estimates were subject to the following qualifications. They did not allow for costs

> involved in any transition to use of Canadian crude such as those arising out of the abandonment or a reduction in the level of operation of the Montreal-Portland pipeline, or possible losses associated with other investment, such as wharfage facilities or tanker commitments. On the other hand, they do not take into account any premium which might be accorded to Canadian due to their relatively higher A.P.I. gravity compared with the majority of crude imported into Montreal.[27]

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[26] Canada, Second Report, p. 119. Price changes in early 1959 did not affect the conclusions concerning the competitive portion of Canadian crude.

[27] Ibid., p. 119.

The Independents presented evidence that Canadian crude could be laid down in Montreal for \$3.15 - \$3.21/bl in the 1961-65 period. This would undersell Venezuelan crude by 21-22¢/bl based on shipping rates of U.S.M.C. -45 to -30. Furthermore they visualized no well-head price reduction would be necessary to land Canadian crude in this market, a market they claimed necessary to ensure continued exploration and development of Western Canadian oil fields. The majors were not of this opinion. They felt a price cut was necessary and that it would lower profits and reduce incentives to develop further oil reserves. It should be mentioned that such arguments naively did not allow for increased volumes of production.

At this point, the major weakness of the Commission's inquiry - its failure to explore the intricacies of world oil prices - should be noted. Scott refers to this weakness.

> One would have hoped, however, that it (the Commission) would have taken time to question whether Canadian crude actually is "competitive" when its price merely matches the posted price abroad plus transportation costs . . . If the Canadian producers wish to get into the American and foreign markets, they must meet the price that implicitly exists within the integrated major companies.[28]

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[28] Anthony Scott, "Policy for Crude Oil," Canadian Journal of Economics and Political Science, XXVIII, (May, 1961), p. 271.

Posted prices were established to ensure the Middle East host governments a "fair" return on their natural resource. Similarly, Venezuelan prices reflected high prices resulting from the effort to develop domestic Untied States production. According to these prices, with the Canadian dollar at par with the American dollar, Canadian Redwater crude laid down at Montreal was at a disadvantage of 23.4¢ compared with Venezuelan crude. When the premium on the Canadian dollar was accounted for, this figure rose to 36¢/bl. In view of the highly competitive atmosphere in the petroleum world at that time, it was not unreasonable to speculate that transactions occurred at less than posted prices.[29] This hypothesis was substantiated by a vice-president of Imperial Oil in a speech outlining the competitive position of Canadian crude. He stated that "if the additional discounts which are now available on imported crude were taken into account the disadvantage would reach well over 40¢/bl."[30]

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[29] This practice has interesting implications for tariff policy. If sales are made at less than posted prices, how large a tariff would have to be levied in order to be prohibitive?

[30] Trevor Moore, Vice-President Imperial Oil Ltd., address to Controllers Institute of America, Toronto, Dec. 8, 1959, cited in Oil in Canada (Jan. 4, 1960), p. 38.

Needless to say to evaluate a situation dependent on so many variables was not any easy task. One of the more objective presentations was made by W.J. Levy, the internationally renowned petroleum consultant who appeared at the request of the Commission. He concluded that the Montreal market was not an obvious direction of the industry's expansion until other markets - the U.S. Midwest and West Coast areas - had been proved unattainable for Canadian crude.

In summary, the Commission recommended that it be national policy

(a) to encourage and permit the export of Canadian crude without license, and

(b) to ensure the continued use, consistent with the interests of the Canadian consumer of petroleum products, of Canadian crude in refining areas of Canada accessible to it by existing pipeline facilities, thereby increasing the market outlets for such crude oil.[31]

Secondly, it recommended that in the Ontario market west of the Ottawa Valley, Canadian crude displace a volume of Montreal refined products of approximately 50,000 b/d. The

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[31] Canada, Second Report, pp. 143-144.

third recommendation urged the Canadian oil industry to strive to enlarge and entrench itself in the U.S. markets especially the West Coast Puget Sound area, where Canadian crude had proven to be competitive. The Commissioners also recommended no action should be taken concerning the construction of pipeline connections to Montreal until the oil industry had an opportunity "to demonstrate that it can find markets elsewhere in Canada and the United States sufficient to sustain a healthy and vigorous Canadian oil industry with the incentive for further exploration and development."[32] The final recommendation, involved subjecting imports to license should such action be necessary to implement the other features of the national policy. By following these guidelines, the Commission hoped the industry would achieve a production target of 700,000b/d by the end of 1960.

The strict government ultimatum so feared by the industry was lacking. In its place was an appeal to the industry to voluntarily "put its affairs in order". The Commission struck a practical compromise by urging the use of domestic crude in Ontario and the expansion of export markets. Neither the majors nor the independents gained all they desired, but if the Commis-

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[32] *Ibid.*, p. 144.

sions' recommendations could be fulfilled the industry would be spared the rod of stricter government control.[33]

Implications of the Royal Commission

Even before the Second Report of the Commission was released, its hearings involving the Montreal pipeline question resulted in an ammendment to the U.S. mandatory import program. On April 30, 1959, crude oil or unfinished products transported overland from the country of production were exempted. In effect, this decree applied only to Canada since pipelines were the sole economic mode of overland transport, and Canada possessed the only significant pipeline connections to the United States. This decision placed Canada in a preferred position relative to Venezuela. The reason given in a White House press release was that such oil would be available overland in event of an emergency. This reason possessed little validity for the east coast of the U.S. which lacked pipeline connections with Canada.[34] More likely, the policy change was a direct result of Canada's threat to construct a Montreal pipeline. If domestic crude were

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[33]With the passage of the National Energy Board Act on July 18, 1959, the government implemented one of the recommendations of the Commissions first report. Under Section 87 of this act, the government could impose mandatory regulations on oil imports and exports.

[34]Edward H. Shaffer, op. cit., p. 118.

utilized in the Montreal market, some form of protection would be required, and foreign crude, largely Venezuelan would lose a valuable market.[35] Such actions could be traced to the unavailability of American markets due to the mandatory import policy, and the Venezuelan government could be expected to complain to the U.S. government that, as a direct result of their quota system, Venezuela had lost an important export market. Thus, the import policy was altered in an attempt to avoid strained relations among the three governments involved.

No government action was taken to adopt the Commissions' recommendations nor to direct the growth of the industry. This inaction can be rationalized by the Canadian exemption discussed above which created an air of optimism in that the outlook for expanding both sales and production seemed highly favorable. Unfortunately, for the Canadian industry by 1960 it became all too apparent that daily crude production would be some 175,000 barrels short of the target of 700,000. While exports grew by 21,000 b/d during the eighteen months immediately following the Commission's report, imports grew. In 1960, alone, "imports of crude oil and refined products into Canada increased, absorbing on the balance all the increase in consumption in the nation,

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[35] In 1958, Canada accounted for 16 per cent of Venezuelan crude exports.

plus making slight inroads on the demand for domestic crude."[36] In the same year, the increase in production of crude and NGL was 4 per cent, 9 per cent less than the 1959 figure.[37] Furthermore, more than once during the year, refiners' nominations for Alberta crude were below the economic minimum.

How had the Canadian oil industry arrived at such a state of distress? Since the Borden Commission, only two or three refiners had assiduously striven to comply with its recommendations. Others had merely taken action or done nothing at all to substitute product runs in Ontario refinereies for runs previously made in Montreal refineries with foreign crude. Particularly influential in causing these difficulties were the aggressive marketing policies of two Montreal area refiners, Canadian Petrofina Limited and B.P. Canada Ltd; who did not possess Ontario refinery capacity, but whose retail outlets stretched as far into Ontario as the Kirkland Lake area. Moreover, jobbers with no stake in refinery or production in Canada were promoting cheap foreign products in the Ontario market.

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[36] Carl Nickle, "1961, A Year of Decision for Oil", Oil in Canada (January 5, 1961), p. 20.

[37] Dave Quirin, op. cit., Chapter 6, p. 22.

In general, the anticipated Canadian markets for Canadian crude did not develop.

Generally the finger has to be pointed at the government for its failure to formally endorse in Borden Commission's recommendations, despite the fact, by virtue of Section 87 of the National Energy Board Act, it had the power to do so. Psychologically, an official government statement would warrant more attention than the recommendations of a Royal Commission. Surely a government statement was needed to convince those doing little or nothing concerning, the voluntary program.[38] Yet, inaction was not the government's sole fault. An apparent offer to sell Canadian wheat in exchange for Russian crude did little to promote a climate conducive to the carrying out of the Commission's proposals.[39] This foreign crude could have entered Ontario directly or displaced Quebec production, forcing these products into the Ontario market. Finally, on February 1, 1961, the Canadian government in announcing its National Oil Policy (N.O.P.)

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[38]History supports this hypothesis. The National Oil Policy, based on the Borden Commission's reccomendations, was rapidly effective.

[39]See "Russia Invades Eastern Canada," Oil in Canada (June 13, 1960), p. 10.

took positive action to restore the health of Canada's ailing petroleum industry.

CHAPTER II

THE NATIONAL OIL POLICY: IMPOSITION, HISTORY, and ASSESSMENT

The Imposition of the National Oil Policy

In view of the fact that some companies publicly stated that they would abide by a National Oil Policy when and if declared but would not take voluntary action (which would have complicated contractual relations outside Canada and adversely affected parent companies), the inaction of the government is incomprehensible. *Oil in Canada* reported that at this time, 75 per cent of the world's petroleum production and reserves were subject to government pressures to expand output and over 75 per cent of world oil markets were removed from "normal" competition by government policies designed to protect or stimulate domestic production.[1] This coupled with the realization that the majority of marketers of foreign oil in Eastern Canada were members of international corporations which abided

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[1] Carl D. Nickle, "The Path to Canadian Oil Saturation," *Oil in Canada* (January 19, 1961), p. 19.

by national oil policies effective elsewhere in the world,[2] further compounds the lack of credibility of government inaction.

Nevertheless, a few words should be said in defense of the government. An unfortunate weakness of the democratic system of government is that often, a party has more to gain (or alternatively less to lose) by inaction. Firstly were the political consequences of higher crude prices in Quebec if domestic crude was given access to the Montreal market and dissatisfaction in the Western producing provinces if it were not. A second factor to be considered was the political unpalatability of stricter government control over the petroleum industry. Finally, until 1960, the industry itself had a divided viewpoint with two camps as illustrated in the Borden Commission hearings: - the independents who wanted a Montreal pipeline and the majors who did not. The Independent Canadian Petroleum Producers' Association, formed late in 1960, submitted a national oil policy which did not call for access to the Montreal market. Thus, for the first time, the industry presented some

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[2] The American, Iranian, French and Argentinian governments had intervened successfully in their country's petroleum affairs.

semblance of a united front.

On February 1, 1961, eighteen months after the advent of the Borden Commission's Report, the Honorable George Hees, Minister of Trade and Commerce, announced the adoption of a National Oil Policy. The essential feature of the policy involved production targets for crude oil and natural gas liquids of 640,000 b/d in 1961, increasing to 800,000 b/d by 1963. This was to be achieved by a combination of three methods. In the first place, in the Ontario market, foreign crude and refined products would be displaced by domestic crude and products. Secondly, products refined from domestic crude in Ontario would be substituted for imported products, or for those refined from foreign crude, in all Ontario west of the Ottawa Valley, i.e. region three. Thirdly, since only a small portion of the anticipated expansion was to come from the normal growth of domestic demand, a vital facet of the program involved increased exports to the United States. The prospects for expanding this market were extremely favorable. Canadian crude was exempt from U.S. quota restrictions and "it was believed that U.S. producers would not oppose an increase in Canadian exports on the ground that Canadian oil would only displace an equivalent quantity of oil imported from other

countries."[3] Also, crude production in the U.S. was expected to decline while demand was expected to grow. This export policy placed a strong burden of responsibility on those producing companies in Canada who lacked Canadian refinery facilities, but who were affiliated with companies owning American refineries. This sentiment was expressed by Mr. Hees in an address to the Canadian Petroleum Association's 1961 Annual Meeting.

> While the government looks to the major integrated companies with refining capacity in Eastern Canada to contribute materially to this policy, it also expects that all producers, especially those having affiliations with refiners in the United States, will do their utmost to find additional market outlets . . .We shall look for the necessary improvement during our assessment of the contribution made by each individual company to the success of the oil policy.[4]

The oil industry received the National Oil Policy as a practical compromise - it did not please everybody, but all agreed they could live under it. It was official (unlike the Borden Commission's recommendation) and firm, yet flexible. Goals were

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[3]Alan R. Plotnick, "Canada's National Oil Policies, How Are They Working Out?" Canadian Business, XXXVII (April 1964), p. 54.

[4]George Hees, speech to the Annual Meeting of the Canadian Petroleum Association, 1961, cited in Oil in Canada (March 23, 1961), p.29.

in general terms of time and quantities with the oil industry free to work out its means of compliance. Most important, the national objectives could be achieved with a minimum of disruption in normal trade patterns. Again, the industry was spared government domination, but if moral suasion failed, the government could legally enforce its policy.

The Effectiveness of the National Oil Policy

The 1961 target was exceeded by some 3,000 b/d, due mainly to the increase in exports. Progress in domestic markets was less gratifying. Poor prairie crop conditions and abnormally high temperatures limited the growth of domestic demand. However, in the Ontario target area, imports of foreign crude - with the exception of minor quantities of specialty crude - were virtually eliminated and direct product imports were decreased by 40 per cent.[5] One inhibiting factor was the lack of refining capacity in the Ontario target area. Meanwhile, for the oil companies, the National Oil Policy meant new investment, temporary reductions in the use of some existing facilities, and the adjustment of existing contracts.

Although the government failed to post any specific target for 1962, the year was one of significant achievement.

[5] National Energy Board, Annual Report 1961, p. 17.

Production was 735,000 b/d, 12 per cent above the 1961 level. Moreover, a greater proportion of the production gain was attributable to the growth in domestic markets. Crude imports into Ontario declined 77.92 per cent from their 1961 level of 7.7 thousand b/d to 1.7 thousand b/d.[6] In addition, the rate of growth of imports into Canada east of the Ottawa Valley decreased, largely due to the reduced product transfers from the Montreal area to Ontario. The industry outlook began to brighten - 1962 marked the first upturn since 1952 in geophysical crew activity, and in 1963, for the first time since Leduc, the industry's revenues exceeded its expenditures.

The year 1963 marks the pinnacle of achievement of the National Oil Policy. Although the target for the year of 800,000 b/d was missed by some 14,000 b/d, this level was exceeded during several months of the year. Exports of crude were up to 248,252 b/d, an increase of 34.65 per cent over 1961. Canadian crude increased both its absolute and relative share of the Puget Sound market with exports averaging 125,938 b/d in 1963, while those to Districts I-IV reached an average

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[6] National Energy Board, Energy Supply and Demand Balances 1955-67, Ottawa, 1968.

level of 122,314 b/d. Progress was also made in the other facet of the policy. Initially, most of the progress stemmed solely from increased exports, but by 1963, the greatest proportional increase in production shifted from gains attributable to growth in exports to increases in domestic market use.[7] Plotnick cites the following trends as illustrative of the progress made in Ontario:

(1) An expansion in the use of domestic crude oil from 197,200 b/d to about 265,000 b/d.

(2) A reduction in imported crude from 10,000 b/d to 1,000 b/d.

(3) A reduction in imported products from 17,400 to 7,000 b/d.

(4) A reduction in the use of products from Quebec from 68,900 to 50,000 b/d.

(5) An over-all rise in oil consumption from 294,100 to 333,000 b/d.

(6) The rate of increase of sale of domestic petroleum increased at a rate greater than the over-all growth of demand.[8]

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[7]However, for the 1960-64 period of the increase in production 55 per cent was due to exports, 45 per cent due to expansion in domestic markets.

[8]Plotnick, Petroleum, Canadian Markets, p. 136.

Two events in the latter part of the year greatly aided these developments. Firstly, Shell's new 31,000 b/d Ontario refinery went on stream. This represented all net gain in the use of domestic crude since Shell had not been using trade out arrangements with other refineries to supply its Ontario market. The second event was the reversal of flow of a section of the Trans-Northern products pipeline. The system continued to move products west from Montreal to Brockville, but the flow was reversed over the rest of the line from Toronto to Kingston. Thus, by 1963, the National Oil Policy owed its success to the plugging of the gaping holes in the domestic market and to expansion in the American export market.

The government deemed it desirable to establish an approximate target of 850,000 b/d for 1964. The Honorable Mitchell Sharpe, then the Minister of Trade and Commerce, explained his reasons for establishing this target.

> Our objective is to consolidate and complete the establishment of Canadian crude as the source of supply for Ontario west of the Ottawa Valley. We cannot press this to the point where there exists an actual shortage of any product but it is essential that transfers and imports be reduced to a minimum.[9]

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[9]Mitchell Sharpe, speech to joint meeting of the Canadian Petroleum Association, the Independent Petroleum Association of Canada, and the Canadian Association of Oilwell Drilling Contractors, cited in Oilweek (February 10, 1964), p. 16.

Ironically it was during this year that imports of gasoline into the Toronto area at distress prices threatened to destroy the industry's co-operation with the National Oil Policy. To prevent dumping the government established a value "for duty" of gas at not less than 10.5¢/gallon for regular and 12.5¢/gallon for premium.

In 1965, although no government targets were posted, exports continued to grow, and now accounted for 53 per cent of the increase in production since 1960. Nevertheless, imports gained more than twice as much as the use of domestic production, with Ontario imports increasing by more than 12,000 b/d. The combined crude and product imports in 1965 of 540,217 b/d constituted 48.6 per cent of the total domestic market, their largest share of the Canadian market since the implementation of the National Oil Policy.[10] Net product transfers into the target area increased 5,175 b/d to 38,646, the first net increase since 1961.[11] Despite the impressive growth of production, reserves had expanded even more rapidly, posing an urgent need for further market expansion.

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[10] "Elephant on a Tightrope," Oilweek (May 23, 1966), p. 37.

[11] National Energy Board, Annual Report 1969, Appendix IX.

Investment in refining capacity in Ontario west of the Ottawa Valley had not kept pace with market requirements. In 1967 the estimated capacity of Ontario refineries was 322.4 M b/d, while demand in the target area was estimated to be 358 M b/d.In the same year, it was judged that Ontario refiners supplied 85.5 per cent of region three's demand.[12] Fortunately, the second Suez crisis in the summer of 1967 postponed a crisis in the domestic petroleum industry just as the 1957 Suez blockade had done.

With the closure of the Suez canal and the temporary shutdown of certain key Middle East pipelines, Canada's exports experienced their largest percentage increase since the 1961-62 impact of the National Oil Policy. Although exports via the Trans-Mountain pipeline were 70,000 b/d above the normally expected level for July through September, exports to the west

Table 10 - 1967 Crude Exports (b/d)

District	Percentage Increase over 1966	Volume
I - IV	22.778	228,070
V	15.46	186,764
Total	19.372	414,834

Source: Calculated from National Energy Board Annual Reports.

[12]National Energy Board, Report on Supply of Petroleum Products and Related Refinery Capacity - Region 3, March 14, 1969, Tables I, II and III.

coast were limited by the capacity of the line. While deliveries to final consumers were uninterruped, Eastern Canadian inventories were run down,[13] and it was rumoured that Eastern Canada was near gas rationing. The National Energy Board mentioned that Canada's emergency exports to the American west coast exceeded by a large volume emergency imports from the United States. The pertinent question to ask is could these imports and exports substitute for each other, and the answer is an emphatic no. While Canada had shut-in capacity, the crisis proved that oil is of no use without transportation facilities. More explicitly, is the oil a resource if it is not readily attainable?

On the import side, however, the outlook was not as bright. Imports increased with the increased demand in Ontario met largely by interprovincial transfers and offshore imports. Attention was diverted away from this problem by the expansion of Canadian exports into the Chicago refinery area via a loop from the Interprovincial Pipeline at Superior. To enter this market, Canadian crude had to face the competition of U.S. Gulf Coast crude delivered by Capline, a large diameter pipeline owned by a consortium of Chicago area refiners. Despite their preference to import wholly-owned versus Canadian prorated

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[13] National Energy Board, Annual Report 1967, p. 10.

crude, the outlook for Canadian crude in this market was bright for three reasons. Firstly, four of the eight Chicago area refiners were not included in the Capline consortium. Secondly, many of the Chicago area refiners, in particular Mobil Oil Ltd., possessed substantial western Canadian reserves. Thirdly, and most important, Canadian crude could be laid down in Chicago at more than competitive prices. One typical estimate appeared in Oilweek. The price of Redwater crude (in U.S. currency) laid down at Superior was $2.90/bl., of this, 36.3¢ was the cost of transportation for the 1,130 miles from Redwater to Superior. Therefore it was not unreasonable to assume the transportation cost of the additional 400 miles to Chicago would be considerably under 50¢/bl. Thus Canadian crude would be competitive with Gulf Coast crude laid down in Chicago at $3.40-$3.50/bl.[14] In return for the loop to Chicago, the Canadian government in a secret agreement undertook to ensure by voluntary means (i.e. moral suasion and arm twisting) to limit exports of crude to District I-IV refineries to no more than 280,000 b/d, in 1968, 306,000 b/d in 1969 and 332,000 b/d in 1970.

Initially the National Oil Policy was weakened by imports of Caribbean and European products that managed to evade

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[14] "Gulf Coast and Canadian Crude Could Clash for Chicago Market," Oilweek (June 6, 1966), p. 12.

the government's anti-dumping regulations. The problem was compounded by the discouraging pace of refinery expansion in Ontario and the expansion of Quebec refinery capacity by Petrofina. Furthermore, in June B.A.'s Clarkson Ontario refinery announced that it was cutting back its refinery operations and correspondingly reducing its purchases of Western Canadian crude, linking the decision with the continued movement of foreign origin gasoline to markets west of the Ottawa valley.

In 1969, the situation was broadly the same, with both exports and trouble with the domestic aspect of the National Oil Policy spiralling. Imports of foreign origin motor gasoline, the critical product for competitive reasons increased. Meanwhile, a National Energy Board study predicted that, while Ontario refinery capacity should soon be adequate to supply the total anticipated demand of motor gasolines and middle destilates, "this is no assurance that this potential supply would be fully taken up and demand for Canadian crude maximized."[15] Whereas foreign originating products reduce the incentive for refinery expansion, the National Energy Board warned that such actions, if continued, would seriously weaken the voluntary basis of the

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[15] National Energy Board, Annual Report, 1969, p. 11.

National Oil Policy.[16] The depth of the problem is illustrated by the following comment.

> Unless the government soon takes action to put teeth in the National Oil Policy and prevent products refined from imported crude leaking west of the Ottawa Valley, Gulf Oil may be forced by economics to breach the National Oil Policy with imported materials. . . .Although only a small volume of products was leaking across the line at present, prices and profitability of Ontario refining operations had been seriously undermined and refiners in the Toronto area were making a considerable financial sacrifice to stay with the National Oil Policy.[17]

An Imperial Oil Company Ltd. spokesman pursued the same line - "if the policy is disregarded by others, Imperial Oil will have to follow suit."[18] In short, the bigger companies with refining capacity in Ontario stated they would no longer stand by if smaller companies flaunted the National Oil Policy.

With the opening of the St. Lawrence Seaway in the spring of 1970, the National Oil Policy was subjected to its stiffest test yet and failed. The Financial Times reported that more than 40 million gallons of foreign gasoline, an amount equal to 40 per cent of the gasoline imports into the Toronto area in

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[16] Ibid., p. 11.

[17] Oilweek (March 2, 1970), p. 13, citing J. McAfee, President, Gulf Oil of Canada.

[18] Edmonton Journal, April 3, 1970, p. 66.

1969, had been imported since the opening of the 1970 shipping season.[19] This led the government to announce on May 7, 1970, the enforcement of the National Oil Policy. Energy Minister J.J. Greene told the Commons that "the National Oil Policy is now being jeopardized by the risk of increasing movements of foreign origin products into Canada west of the Ottawa Valley."[20] At the same time he announced that he had invoked Section 87 of the National Energy Board Act which enabled the government to regulate oil trade. In addition, new regulations would require licensing and more in-depth reporting of imports and their distribution. As a result of these restrictions, direct offshore imports into Ontario tapered off, but gasoline from Quebec continued to be a problem.[21]

On the export side, the performance was outstanding, but the prosperity brought surprising developments. Exports rose to a record high of 602,840 b/d, and propagated the trend of disregarding the American government's limitations on exports

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[19] Financial Times of Canada, June 8, 1970, p.3.

[20] Edmonton Journal, May 7, 1970, p. 1.

[21] Ibid., July 7, 1970, p. 1. Gulf Oil announced a 40 per cent cutback at its Clarkson, Ontario refinery. Commencing July 15, purchases of western Canadian crude were reduced 25,000 b/d. The reason given was that orders from companies which had formerly relied on imports did not materialize.

to Districts I-IV.

Table 11 - Exports to Districts I-IV

	Actual	Limit by 1967 secret agreement
1968	298,382	280,000
1969	347,700	306,000

Source: National Energy Board, Annual Reports.

The National Energy Board rationalized their disciplinary inaction. "Although the Board received the co-operation of the great majority of the companies involved, a changing industry environment, in particular increases in U.S. crude oil prices . . . made it impracticable to limit exports to target levels."[22] The fears that Capline would destroy the Canadian market in the Chicago area proved to be unjustified. The line was running at full capacity and still a backlog of demand existed. Chicago area refiners seized the opportunity to buy Canadian crude which enjoyed a price advantage of 45 - 70¢ per barrel, even after paying a tariff of 10.1¢ per barrel.[23] For the first two months of 1970, exports east of the Rockies

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[22] Edmonton Journal, April 21, 1970, p. 13.

[23] Ibid., March 11, 1970, p. 1.

averaged about 560,000 barrels a day. Total export demand of 800,000 b/d would undoubtedly have been larger if it were not for constraints imposed by the capacities of the two pipeline systems.[24]

On March 10, 1970, citing the voluntary control program as unworkable, President Nixon announced limitations on crude oil imports into Districts I-IV. His statement added that voluntary controls broke down, "impairing the management of the present import control program and the orderly development of future oil import policies."[25] The new level was set at 395,000 b/d, an increase over the 332,000 b/d set by the 1967 agreement, but less than recent 1970 levels.

The most recent blow to the National Oil Policy was struck on August 4, 1970, when Mr. Justice W.R. Jackett, President of the Exchequer Court, ruled that the powers invoked May 7, 1970 under the National Energy Board Act were beyond Parliament's authority. The grounds for the decision was the unconstitutional intervention of the Federal government in intra-provincial trade.[26] In other words, once the gasoline

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[24] Ibid., March 11, 1970, p. 1.

[25] Ibid., March 10, 1970, p. 1.

[26] The Globe and Mail Report on Business, August 13, 1970, p.1.

is imported into a province, the National Energy Board cannot regulate its marketing within that province. The most obvious solution would have been to re-align the dividing line between the regions to coincide with the Ontario-Quebec border. However, if this were done, it would be impossible to meet Ontario demands from existing Ontario refineries.[27] Therefore, on August 13, 1970, the National Energy Board imposed new regulations under which it will judge whether "applications to import motor gasoline are consistent with the development of Canada's own oil resources."[28] The industry welcomed this announcement as a sign that the government intends to pursue the National Oil Policy. Nevertheless, it remains to be seen whether these restrictions have gone far enough. There are still no regulations on the movement west of the dividing line of gasoline refined from imported crude in Quebec.

A Brief Assessment of the National Oil Policy

The objective of the National Oil Policy was to maintain a healthy producing industry. Until 1964, the government set this goal in terms of production targets, and by this criterion,

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[27] Ibid.

[28] Edmonton Journal, August 14, 1970, p. 1.

the policy was successful due to both increased exports and drastically reduced imports. Since 1964, no specific targets have been set, and the National Oil Policy has muddled through without clearly defined goals. The modest degree of success that the policy has achieved in recent years was due primarily to huge increases in exports that have effectively raised Canada's net self-sufficiency in crude to 89.5 per cent in 1969 with 92 per cent predicted for 1970.[29] Yet, before final judgement is passed, a multitude of questions should be levied at the National Oil Policy. Our discussion will consider the following questions: What has been the balance of payments effect of the policy? Has the National Oil Policy entailed any consumer costs and losses in economic efficiency to Canadians? Finally, has the National Oil Policy been consistent with other government policies?

The Petroleum Trade Balance:

Although sufficient attention is accorded to Canada's net petroleum self-sufficiency position, little attention is

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[29]"Consumption Matches 1969 Growth," Oilweek, (April 20, 1970), p. 46.

paid to her petroleum trade balance of payments. It does not seem unreasonable to speak in dollar terms of self-sufficiency rather than quantity terms when analyzing the National Oil Policy. The trade effects of the National Oil Policy can briefly be summarized as buying cheap and selling dear. As mentioned previously, cheap foreign crude is utilized in areas east of the Ottawa Valley, with areas west of this line preserved for domestic crude. The export facet of the National Oil Policy entails selling dear in American markets in which high prices are the result of protection afforded domestic crude.

Table 12 - Crude Oil Trade Balance - (Millions of dollars)

Year	Value of crude exports	Value of crude imports	Deficit (-) Surplus (+)
1956	103.9	270.9	-166.9
1957	140.9	305.6	-164.6
1958	73.0	273.9	-200.9
1960	74.5	277.5	-202.9
1961	154.3	291.2	-136.9
1962	232.5	304.9	- 72.4
1963	233.9	334.8	-100.9
1964	262.0	320.6	- 58.6
1965	279.9	312.3	- 32.3
1966	321.7	299.0	+ 22.7
1967	397.9	355.9	+ 41.9
1968	446.4	372.6	+ 73.8
1969	525.6	393.5	+132.3

Source: Dominion Bureau of Statistics, Trade of Canada, Imports by Commodity and Exports by Commodity, various issues.

Table 12 summarizes the development of the crude oil trade. With the development of the Canadian petroleum industry, the trend was one of decreasing deficits. In the 1957-58 period of turmoil in Canadian industry, the deficit increased, only to commence a continuous decline following the implementation of the National Oil Policy in 1961. The first surplus in the crude trade was experienced in 1966, while subsequent years were marked by increasing surpluses.

Table 13 presents the more illuminating results - the overall petroleum trade balance. Although most export earnings were due to exports of crude, exports of gasoline, fuel oil and lubricating oils and greases were also considered. Since a considerable volume of products (in addition to crude) were imported under the National Oil Policy, the following products were considered: aviation gasoline and turbine fuel, heavy and light fuel oil, gasoline, and stove oil. Note that on the overall balance of the petroleum trade (i.e. crude and product exports versus crude and product imports) Canada had never experienced a surplus. However, since the establishment of the National Oil Policy, the deficits have been decreasing with the lowest deficit recorded in 1969 as a direct result of the rapid expansion of crude exports. Despite its aforementioned weaknesses, the National

Oil Policy has succeeded in reducing the deficit on the petroleum trade to around one-twentieth of that experienced before the National Oil Policy.

Table 13 - The Overall Petroleum Trade Balance (Crude and Products) (Millions of dollars)

Year	Net Deficit
1956	234.6
1957	264.7
1958	314.0
1959	209.2
1960	265.0
1961	262.0
1962	130.9
1963	167.4
1964	133.2
1965	144.1
1966	81.7
1967	81.6
1968	81.9
1969	11.9

Source: calculated from Dominion Bureau of Statistics, Trade of Canada, Imports and Exports by Commodity.

These bold estimates paint an impressive picture of the success of the National Oil Policy, but it may be more revealing to compare these results with results that could have been achieved by other policies. There may have been some balance of payment cost that is not revealed in the

in the original estimate. The alternative policies that will be evaluated involve the use of domestic crude in the majority of Canadian markets. Under two such possible policies, imports of offshore crude would have been limited to either

(a) 10 per cent of domestic demand (a minimum in view of needs for specialty crudes and products) or

(b) 17.3 per cent of domestic demand (i.e. imports at a rate similar to that in effect in the United States).[30]

Since it is highly likely that import restrictions would result in varying degrees of loss of export markets, four subcases of both policy (a) and policy (b) were considered. The analysis is predicated on the assumption that these would involve only crude, not products, and would occur in the U.S. Pacific Northwest, the only market where Canadian exports compete directly with overseas crude. No allowance was made for losses in the U.S. midwest where Canadian crude enjoys a relatively safe

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[30]National Energy Board, Energy Supply and Demand in Canada and Export Demand for Canadian Energy, 1966 to 1990, Ottawa, 1969, pages 54-55.

competitive advantage.[31] Alternately, it was assumed that 25, 50, 75 and 100 per cent of this Pacific market was lost. Furthermore, it was also assumed that imports would be reduced gradually. This assumption reflects the fact that to achieve the target level of imports would require considerable time. However, if the alternative policy had been implemented at the same time as the National Oil Policy was implemented, the necessary adjustments could have been completed by 1969. Therefore, an attempt was made to draw a hypothetical picture of Canada's petroleum trade balance at the end of 1969.

In 1969, imports of crude and products comprised approximately 50 per cent of domestic petroleum consumption. This would mean that imports would have been 20 per cent or 34.6 per cent, respectively, of their 1969 levels if the first or second import policy had been successfully imple-

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[31]The Alberta Oil and Gas Conservation Board in a statement of Alberta's crude competitive position (November 15, 1969) reported that Redwater laid down at Detroit had an advantage of 51¢/bl over U.S. domestic crude. The reason used to justify the assumption of lost west coast markets was that overseas producers would demand additional U.S. markets to compensate for lost Canadian markets.

mented. Using these percentages and actual 1969 imports, four hypothetical values of imports (depending on the degree of market loss) were calculated for policies "a" and "b". The surprising results are summarized in Table 14. Choosing the most adverse case (i.e. 100 per cent market loss in the U.S. Pacific Northwest), the overall petroleum trade account would present a surplus of $242.7 million and $162.2 million in cases "a" and "b" respectively. Considering the actual 1969 situation as presented in Table 13, policies "a" and "b" could have provided a balance of payments saving of $254.6 million and $174.1 million respectively.[32]

Table 14 - Petroleum Trade Balance Under Alternative Policies - (Surplus in million dollars)

Proportional loss of Export Market	B of P Petroleum Account	
	Policy "a"	Policy "b"
100%	242.7	162.2
75%	292.0	211.7
50%	340.9	259.6
25%	389.9	311.5

Source: Author's calculations from figures from D B S Trade of Canada Imports by Commodities and Exports by Commodities, various issues.

[32] An additional virtue of these policies is that, unlike the current National Oil Policy, the target level of imports is clearly specified.

While it is realized that these are very rough estimates, they suggest that policies other than the existing National Oil Policy could have resulted in substantial balance of payments savings for Canada. This is not to say that balance of payments considerations alone should be construed to be sound reasons for protectionist commercial policies. The National Oil Policy was a policy to ensure development of the Canadian petroleum industry, not a policy to affect the balance of payments. The balance of payments effects were incidental to the National Oil Policy, however, and, as shown, were quite large. Nevertheless, other considerations should enter the picture. The foremost one is the additional cost to consumers who must pay a higher price for oil because of the policy of protection.

Consumer Costs

Under the National Oil Policy, Ontario consumers who have been forced to use domestic crude have paid more than they would if they could have utilized foreign crude. Although this cost has been estimated to be in the neighbourhood of $60 million per year,[33] several tangential questions need to be examined. It is an economic certainty that the cartel companies are price

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[33]Earle Gray, "Separation Would Be Economic Disaster," Oilweek (April 27, 1970), p. 5.

discriminators - i.e. no matter what the laid-down price of western Canadian crude in eastern Canada, (as long as it is above the price of offshore crude), these companies would price their foreign crude marginally below the price of domestic crude in order to maintain a market for wholly owned crude. To the extent that foreign crude could be laid down more cheaply than indicated by posted prices, any estimate of the costs of using domestic crude would be downwardly biased. On the other hand, in the past Montreal cartel refineries have paid more than the world price for offshore crude. In light of this, consumer costs of the National Oil Policy would be underestimated.

On the positive side of the ledger are the benefits of a secure source of supply and the savings offered to eastern Canadian consumers by cheap western Canadian natural gas. The bountiful supply of gas, by and large a complement of both oil exploration and production - would not exist without the oil industry. Secondly, any estimate of the benefits and costs of the National Oil Policy must consider the substantial revenues from taxes, leases, and royalties that accrued to both the federal and provincial governments.[34] If markets were

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[34] Oilweek (February 23, 1970), page 90 estimated the four western provincial governments' oil revenue in the post-Leduc era to be $3.44 billion. Alberta alone received $2.87 billion.

diminished (for example, Ontario served by foreign crude), other forms of revenue collection would need to be implemented to pick up the slack.

In defense of higher costs to Ontario consumers, some economists and politicians have put forth the notion that this situation is an economic parallel of the protection afforded eastern Canadian manufacturers which results in higher prices in western Canada for manufactured goods. However, to justify the protection of the Ontario market on this basis is erroneous. Two economic "wrongs" do not make an economic "right".

The fact that the National Oil Policy represented a move away from competitiveness of the world market and a step toward the protected price structure of the North American market creates several factors which warrant consideration. Depending upon the elasticity of demand for petroleum products, the higher price afforded to domestic producers could be at the expense of considerable foregone consumption. In addition, the National Oil Policy could involve several efficiency losses. Resources - not only crude but also drilling equipment, manpower etc. - are utilized in less than an optimal fashion. Perhaps Canada should utilize foreign crude to the utmost extent, preserving her crude in anticipation of greater revenue if and when the market warrants

its use.[35]

Distortions are perpetuated not only in other phases of the industry but also in other sectors of the economy. Refinery subsidies and sub-optimal refinery locations exemplify the former,[36] while an example of the latter is industries which use energy derived from oil or which use oil products as an input. Since those who receive higher prices have different consumption patterns than those who pay the higher prices, the ultimate quantity and product mix of the economy is altered.

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[35]Such a policy is predicated on the belief that the National Oil Policy's unofficial import restrictions cause a substitution of high cost for low cost energy while at the same time domestic resources are unnecessarily depleted. Considering the revenue generated by the domestic oil industry, such a policy is highly unlikely.

[36]With unrestricted imports, Quebec refining capacity would be expanded to serve more of the Ontario market. Quirin, (Chapter 3, page 12), is of the opinion that the spectacular increase in Maritime refining capacity may have been a direct result of the fear the National Oil Policy would be amended to force Montreal refiners to use domestic crude. Transportation costs would exempt Maritime refineries from this policy.

<u>Inconsistent Government Policies</u>:

The weakness in the National Oil Policy structure can be summed up as "tough on exports, soft on imports." The import situation was aggravated by inconsistent government policies which involved the reservation of markets and subsidized investment policies. With the aid of federal tax assistance and funds, refineries were constructed in areas of the Atlantic provinces and Quebec having excessive unemployment, high debt and low investment ratios. Both the Golden Eagle refinery at St. Romauld and the Gulf refinery at Point Tupper will receive five million dollars if completion deadlines are met. Considerably more assistance is available through area development agencies.[37] The appeal of such refineries is based on the economics of low cost imported crude which can be processed and sold at a competitive advantage in the Ontario market, thus shrinking the market for Canadian crude. If current plans are carried out, in 1971 capacity east of the Ottawa Valley will be 870 M b/d, whereas demand will be 780 M b/d. District 3 is the obvious market for the excess supply of products. Federal and provincial policies also conflicted. While the

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[37] Letter from R.E. Boston, Director Operations Research Branch, National Energy Board, July 15, 1970.

former stimulated the discovery and development of oil reserves through taxation and informal import controls, the latter were aimed at "improving recovery and substaining the value of oil by limiting production."[38] In order for Canadian crude to remain nearly competitive with foreign crude in Ontario, Canadian prices were maintained at a level below American prices. Thus this price differential, an indirect result of reserving the Ontario market for Canadian crude, made Canadian crude attractive to American buyers, exports soared, and eventually the White House intervened.

To conclude the industry now faces the same problem as it did in 1959-60, but with additional complications in both domestic and export markets that are direct results of the National Oil Policy. Clearly, the policy is in need of revision.

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[38]Wallace F. Lovejoy and Paul T. Homan with Charles Galvin, "A Study of the Problems of Cost Analysis in the Petroleum Industry," Journal of the Graduate Research Center of Southern Methodist University, VXXXI, Numbers 1 and 2, (February, 1963), page 85.

CHAPTER III

THE MARKET PROSPECTS FOR CANADIAN CRUDE

Four markets - Canada, Europe, Japan, and the United States - are considered to be the most likely areas of expansion of Canadian crude oil sales. Before discussing future markets for Canadian crude, however, a few words need to be said about the difficulties and problems encountered in making forecasts in the petroleum industry.

Problems in Forecasting

The Canadian petroleum scene is but a very minute facet of an ultra-complicated world petroleum picture that is dominated by an eight member oil cartel. Five of these companies - Standard Oil of New Jersey, the Royal Dutch Shell Group, Gulf Oil Corporation, Texaco Inc., and Standard Oil Company of California - operate large integrated subsidiaries in Canada. The remaining three cartel companies - Socony Mobil Oil Company Ltd., the French Group, and British Petroleum Company Limited - have Canadian production facilities, while

only B.P. has significant market outlets.[1] In total these companies control 77 per cent of all Canadian retail outlets[2] and 83 per cent of all Canadian refining capacity.[3] In addition the cartel produces 87 per cent of all crude produced in Venezuela, 90 per cent of that produced in Iran, and 100 per cent of that produced in Iraq, Qatar, Kuwait, Saudi Arabia, and Indonesia.[4] Obviously, the cartel has a firm grasp on the reins of the world oil industry. For this reason, marketing of Canadian oil is by and large under control of these international corporations. Predictions of their future decisions and government reactions is, at best, a very precarious proposition.

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[1] Report of the Gasoline Marketing Enquiry Committee to the Honorable A. Russell Patrick, Minister of Industry and Tourism, Government of Alberta, Kenneth A. McKenzie, chairman, December, 1968, pp. 601-613.

[2] Calculated from figures in Petroleum News: Factbook Issue, mid-May, 1970.

[3] Calculated from figures in Oil and Gas Journal, April 6, 1970, pp. 142-144.

[4] Calculated from Petroleum Press Service, various issues, and World Petroleum Review, 1969.

Furthermore, the world petroleum picture is constantly changing. At this time, two large discoveries - the Alaskan North Slope and the North Sea discoveries - have overnight radically altered the world's petroleum reserves. These discoveries illustrate that future finds in the Arctic and offshore areas of North America could bring about further alterations in the North American petroleum industry. The reactions of governments and the cartel companies to these new discoveries raise a number of questions which limit the accuracy of petroleum predictions:

(1) When will large-scale drilling activity be commenced to find these reserves?

(2) Which region will be developed first and thereby pre-empt transportation investment capital and markets?

(3) Will the regional price structure make one particular region's reserves preferable to others?

(4) What will be the policies of the Canadian and United States Governments respecting domestic production, imports and exports of oil?

(5) How will the timing and relative cost of new discoveries and their relative proximity to markets affect the production from developed

reserves and the rate of finding replacement reserves?[5]

With these limitations in mind, an attempt will be made to sketch the market prospects for Canadian crude.

The Market Prospects

The First Prospect: Self-Sufficiency:

This prediction of self-sufficiency is based on three views of the Canadian oil scene. Firstly, the Arctic Islands' potential has been rated as outstanding, reflecting the promising formations found there.[6] Secondly, there are exciting oil prospects in Canada's offshore Atlantic areas, particularly the Nova Scotian shelf.[7] Recently a senior

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[5] The National Energy Board, Energy Supply and Demand in Canada, p. 49.

[6] De Golyer and MacNaughton, a respected oil consulting firm estimated Canadian Arctic reserves to exceed 40 billion barrels. They also felt that this could easily prove to be a conservative estimate.

[7] The Edmonton Journal, June 24, 1970, p. 87.

executive of the Royal Dutch Shell Group was quoted as saying he would not be surprised if his company discovered an oilfield in the Maritimes as "good as the recent Alaska discovery."[8] A virtue of these vast offshore reserves (estimated to be 90 billion barrels of recoverable oil)[9] is that they are advantageously located with respect to the Montreal refining market. Thirdly, it is possible that either synthetic crude or conventional western Canadian crude could be laid down competitively in eastern Canada. The present competitive position of Canadian crude versus overseas crude is as follows:

Table 15 - Competitive Position of Canadian Crude in Montreal, December 16, 1969.

Source	Posted F.O.B. or Wellhead Price/bl.	Laid-down Cost Montreal* Tanker	Portland	All Can. route
Redwater	$2.62 (Can.)			$3.29
Venezuela				
Oficiana	$2.80 (U.S.)	$3.26	$3.31	
San Joaquin	$3.10 "	$3.58	$3.63	
Middle East				
Arabian	$2.17 "	$2.69		

*Prices in Canadian dollars.

Source: Alberta Oil and Gas Conservation Board, Alberta Crude Oil Competitive Position, December 16, 1969, Table 1.

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[8]The Financial Post, March 2, 1970, p. A-2.

[9]National Energy Board, Energy Supply and Demand in Canada, p. 57. It is interesting to note the growth of estimated reserves. Oilweek (May 12, 1969, p. 46) estimated offshore reserves at

From these figures it is obvious that wellhead prices and/or transportation costs need to be reduced before Canadian crude can be competitive. Therefore, at present, Canada's best hope for total self-sufficiency appears to be the development of offshore crude.

The Second Prospect: The European Market:

Because of its rapid rate of growth of demand and its high percentage of imports in total consumption, the western European market was considered a prime market for both our synthetic and conventional crude.[10] Since about 90 per cent of its oil is imported from overseas, particularly the Middle East, western Europe is anxious to diversify its suppliers. The discovery of reserves estimated to be in excess of 7 million barrels in the Echofish field in the North Sea will favourably alter the petroleum supply pattern, but will only raise the level of self-sufficiency to about 20 per cent.[11] Present demand is 12 million b/d, and growing at a rate of nearly one million b/d annually. "To supply present demand with a 20-year reserves-

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36.37 billion barrels.

[10]For a typical discussion see Alan R. Plotnick, "Market Prospects for Canada's Tarsands," The Business Quarterly, 27-28, 1962-63, p. 82.

[11]Earle Gray, "Some Implications of North Sea Oil," Oilweek (June 8, 1970), p. 5.

life supply would require 90 billion barrels of proven recoverable oil reserves."[12]

Since this new North Sea oil will likely sell for $2.00 at the wellhead, Canadian crude of any type will not be able to undersell this crude in the near future. With tar sands production at 500,000 b/d, Plotnick estimated the cost per barrel to be $1.50 in the tar sands. He predicted pipeline and tanker rates would fall from their present level of $1.15 to $1.00, yielding a laid-down cost of $2.50 per barrel in London.[13] Given the radical price reduction necessary for tar sand oil to be competitive, the uncertain state of Arctic oil tanker transportation, and the North Sea discoveries, it can be concluded that Canada will not serve Europe as an economical source of supply in the near future.

The Third Prospect: The Japanese Market:

Having been shut out of the European market (in the near future at least), Canada should redirect her search for markets to the east. Here, the most likely customer for Canadian

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[12] Ibid.

[13] Alan R. Plotnick, The Business Quarterly, p. 79.

crude would be petroleum-thirsty Japan. Oilweek estimated that Japan, the world's second largest importer, will increase its consumption by 170 per cent between 1965 and 1975, and double again by 1985.[14] For the following reasons the outlook for Canadian crude in this market is promising. Firstly, 90 per cent of Japan's present oil imports stem from the Middle East, and supply diversification is favoured. Secondly, Canadian Arctic fields are some 4,000 miles closer to Japan than her present sources of supply. Thirdly, there is a well-established trade relationship between Canada and Japan. Japan is threatening to replace Britain as our second largest trading partner, and already has purchased substantial amounts of western Canadian mineral products.

However, some form of price reduction is necessary to make Canadian crude competitive. At present, Japan pays approximately $2.15 per barrel for Middle East crude laid down in Japan, whereas the delivered price of Canadian crude would be in the range of $3.50 - $3.75 per barrel.[15] Economies in

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[14] "Oil Exports to Japan Competitive at $1.40," Oilweek (February 5, 1968), p. 16.

[15] Journal of Commerce, (January 22, 1970).

transportation could be achieved by an 800 mile pipeline from the oil sands to Prince Rupert. From this port, the voyage to Japan is some two days shorter than from Vancouver. However, because of the present price disadvantage of synthetic crude, Japanese interest in the tar sands has waned. Nevertheless, the outlook is somewhat brighter for Arctic crude. An official of a Japanese petroleum company optimistically predicted that Canadian Arctic crude

> could be laid down at a price equivalent to that paid for imports from Kuwait . . . But when the additional cost of desulphurization of Kuwait oil is calculated, the Arctic price would in fact be lower.[16]

This estimate must be considered with caution for, in the first place, the price of Arctic crude will undoubtedly reflect the North American price structure, and in the second place, although Arctic oil supplies would be 4,000 miles closer to Japan than the Middle East, transportation costs from the latter would be less than from the former area despite the distance advantage. Arctic oil would require high cost pipeline transportation for a substantial portion of the distance while Mid-East and African

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[16]Keisuke Idemitsu, President, Idemitsu Kosan, cited in Oilweek (March 30, 1970), p. 19.

crude is moved to Japan by extremely low-cost tanker.

Yet, there is reason for optimism. In summary, both synthetic and Arctic crude could become competitive. New port facilities could be constructed to allow for supertankers and the economies which they generate. Perhaps long-term contracts could be worked out to ensure Japan a secure source of supply, for which she may be willing to pay a slight premium.[17] There is the possibility of implementing a two-price system. Low cost crude would be earmarked for premium markets (Japan), while higher cost (and higher priced) crude would be used in the North American market.[18] Finally, there is the compatibility of Japanese petroleum needs with those energy needs of North America. The Japanese are interested in petroleum alone, not natural gas, while the United States is most desperate for natural gas. In conclusion, a reflection on recent developments in the Western Canadian coal industry buoys the hope that Canadian crude may someday tap the Japanese market.

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[17] Since her industry is dependent upon cheap energy, this premium would need to be very small.

[18] This possibility is explored by R.A. Fraser in a forthcoming M.A. thesis, University of Alberta.

The Fourth Prospect: The United States Market:

The American Supply Deficiency:

In both the short and long runs, the American market holds the most promise of increased Canadian exports. In the short run it is apparent that the American independents, the prime supporters of import restrictions, will not be able to close the demand-supply gap from domestic production without increasing retail prices of gasoline and other petroleum products. In these times of inflationary pressures, public opinion will oppose such price increases, and will provide President Nixon with a tool to combat the powerful protectionist lobbies of the independent producers. In addition, some Northern refineries were constructed specifically to utilize Canadian crude, and with the cut-back in imports they have been operating at less than capacity. Thus while the exact duration of the American "power play" in energy negotiations is unknown, it is expected to be reasonably brief.

What is known, however, is that the United States faces a serious demand-supply gap in the future. Estimates of 1980 demand vary between 19.4 MM b/d and 25.0 MM b/d. The supply deficiency (i.e. the difference between United States demand and domestic production plus overseas imports) historically

has been filled with exempt overland imports, primarily from Canada. This deficiency provides the opportunity for Canada to supply oil to her southern neighbour. "Any other possible means of meeting the deficiency are a presently unforeseen increase in production in the "lower 48" states, or United States offshore production, additional imports of foreign oil, and the development of synthetic or unconventional oil supplies from oil shales or coal."[19]

The National Energy Board predicted that production in the lower 48 states would peak before 1975 at an approximate level of 11 MM b/d. In addition,

> it will require an extraordinary level of exploration effort with corresponding high success ratios to achieve and to maintain such production at a rate of 11 to 12 MM b/d, while at the same time maintaining a reserve to production ratio near the current level. To illustrate, at this rate of production it would be necessary to discover in the "lower 48" the equivalent of a 25 billion barrel "Prudhoe Bay" field every six years (60 per cent of present reserves); it would be necessary to find the equivalent of Canada's entire current recoverable reserves every two and one-half years.[20]

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[19] The National Energy Board, <u>Energy Supply and Demand in Canada</u>, p. 50.

[20] <u>Ibid</u>.

The obvious effect of the North Slope discoveries will be to reduce Canadian exports into District V, but these Alaskan reserves are insufficient to radically alter this deficiency.[21] Under various assumptions concerning North Slope production, the National Energy Board estimated the supply deficiency. The results, summarized in Table 16, point out that there will be a large and growing supply deficiency to which Canadian exports could make a substantial contribution.

Table 16 - Projected American Petroleum Supply Deficiency

North Slope Production (MM b/d)	1975	1980	1985	1990
1	1.8-0.8	4.9-3.0	6.6-6.0	9.5
2.5	1.6-0.6	2.5-1.8	5.1-4.8	8.0
4.0	1.6-0.6	2.5-1.9	4.4-4.1	7.4

Source: National Energy Board, Energy Supply and Demand in Canada, page 53.

The Failure of Present American Policies

To succinctly summarize the American situation, the United States is skewered on a two-pronged fork. Under the guise of security reasons, domestic production has been protected,

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[21] Present North Slope reserve estimates vary between 12-15 billion barrels. At 1980 consumption levels, these reserves would last only two years. (The Albertan, May 30, 1970, page 31.)

resulting in high product prices for the American consumer. Unfortunately, the high price it is paying for domestic oil has not produced the reserves which the United States requires. If Alaska is excluded, the American reserves life index has fallen continuously from 3.8 million barrels in 1961 to 9.7 million barrels in 1969.[22] In the interval from 1964 to 1968, expenditures for exploration, development, drilling and producing facilities amounted to more than $25 billion. This figure was more than seven times the amount spent in western Canada, but the additions to proved reserves were only 2.7 times as great as the additions in western Canada.[23] This lack of success is underlined by the reserves finding record presented in Table 17. Moreover, the cost of finding, drilling development wells and installing productive capacity in the United States was $1.16 per barrel - 45¢ greater than the comparable western Canadian figure.[24]

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[22] "Frontier Oil and Gas Reserves Needed," Oilweek (April 20, 1970), p. 42.

[23] "U.S. Doubles Canada's Costs," Oilweek (February 23, 1970), p. 83.

[24] Ibid.

Table 17 - Reserves Finding Record for United States and Canada

Area	Reserves per foot drilled	Reserves per well drilled
	1960-69 (Bls. of oil)	
U.S. lower 48 states	18.2 bls.	81,400 bls.
Alaska	126.5 bls.	1,283,000 bls.
Canada	68.8 bls	312,700 bls.
Alberta	88.8 bls	482,300 bls.

Source: Oilweek (April 20, 1970), page 42.

Since the import restrictions have been brought about the proposed benefits, the costs have been unwarranted. The annual cost of this program has been estimated to be between \$5.28 and \$7.2 billion; over the last ten years, the total cost would be in the neighbourhood of \$40 - \$70 billion. Conservative estimates of additional annual petroleum costs for an average family of four in the states of New York, Vermont and Wyoming were \$102.32, \$195.92 and \$258.00 respectively.[25] The American Cabinet Task Force on Oil Import Controls projected that, by 1980, annual costs would soar to \$8.4 billion.[26]

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[25] The Montreal Star, March 12, 1970, p. 63.

[26] The Cabinet Task Force on Oil Import Control, George P. Shultz, chairman, The Oil Import Question - A Report on the Relationship of Oil Imports to National Security, (Washington: February, 1970), p. 22.

One misconception concerning the competitiveness of Alaskan North Slope crude should be cleared up. An American government study group found that this oil would be competitive in the United States, Japan and Northern Europe. These findings were based on a wellhead price of 36¢ per barrel and a laid-down price at Valdez of 81¢ per barrel. Via tanker and pipeline this crude would be laid down at Chicago for $1.36 per barrel, and via the Panama Canal at the East coast for $1.81. If foreign tankers were used, the Japanese laid-down price would be $1.00 per barrel.[27] Maurice Adelman of M.I.T. calculated the laid-down East coast price to be $1.10 per barrel (if foreign tankers were used) and 85¢ per barrel in Japan. These estimates are very imprecise approximations. Firstly, the estimate was prepared at a stage of development at which cost information was at a premium. Secondly, the government study group estimate did not include lease costs and Adelman's estimate represented real costs and excluded profits and state taxes.[28] In reality, there are several

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[27] Clyde La Motte, "North Slope Oil Said Competitive," Oilweek (August 11, 1969), p. 10.

[28] An earlier estimate prepared by Dr. D. E. Armstrong of McGill University (Oilweek April 4, 1966, page 20), found the social cost of a barrel of Canadian oil - i.e. the real cost of finding and producing a barrel of oil in terms of labour and machinery costs excluding such costs as royalties, taxes and land costs (which he did not consider to be real costs to the economy) was $1.00 per barrel.

Canadian fields that could be produced profitably at 50¢ per barrel or less if royalties (about 27¢ per barrel) and government lease costs (about 20¢ per barrel) were ignored.[29] Therefore it does not appear that Alaskan crude will completely wipe out the price advantage Canadian crude has in some American markets.

A more realistic estimate was prepared by President Nixon's Cabinet Task Force, which anticipated a Prudhoe wellhead price of slightly under $2.00 per barrel.[30] But this estimate was prepared on the assumption of a pipeline connecting Prudhoe to Edmonton via the MacKenzie Valley. This route possesses some economic advantages. From Prudhoe to Chicago via Edmonton is a distance of some 3,100 pipeline miles. Via T.A.P. and tanker to Puget Sound and thence by pipeline to Chicago represents an additional 1,200 miles and an additional 15-50¢ in transportation costs. In addition, deliveries via the MacKenzie route would be more secure from physical interruption and less subject to export diversion in an emergency than tanker deliveries. The price Americans would have to pay for this pipeline would involve greater access for Canadian crude to American markets. Since this line would not only transport Alaskan crude but would also

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[29] Oilweek (August 18, 1969), p. 3.

[30] Clyde La Motte, "U.S. Task Force Pushes Continental Energy Integration," Oilweek (December 22, 1969), p. 8.

tap any additional Canadian discoveries along its route, the potential for increased exports is further enhanced.

Lending support to greater crude exports is a situation created by the United States' desperate natural gas shortage.[31] As a result, the United States is highly desirous of tapping the vast gas fields of the North Slope. Whereas there is some uncertainty that a crude oil pipeline will be constructed, it is a virtual certainty that a natural gas line will follow a Canadian route from Alaska. To transport natural gas entails expensive liquefying, loading and storage facilities. A tanker capable of carrying 450,000 barrels of L.N.G. (equivalent to about 900,000 barrels of crude oil) costs $22 million, whereas a tanker capable of transporting 1.8 million barrels of crude costs $17 million.[32] Even failing the construction of a crude line, it appears a gas line is desired. Therefore Canada

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[31] The Edmonton Journal, April 11, 1970, p. 18, reported American natural gas consumption exceeded the discovery of additional reserves by 5 trillion cubic feet in 1968.

[32] Earle Gray, "Continental Policies in New Perspectives," Oilweek (June 30, 1969), p. 3.

can use this as a level to pry open the American market for Canadian crude.[33]

In summary, the American supply deficiency, the inability of Alaskan crude to completely displace Canadian crude in the American market, and the American need for Canadian co-operation in future transport systems (either land or water), point to increased Canadian crude exports to the United States.

The Foster study singled out District II as the most promising market area for Canadian crude, and predicted 80 per cent saturation by Canadian crude in the Detroit-Chicago-Toledo area with integrated oil policies.[34] Additional expansion into District I was foreseen. From the data presented in Table 18, the competitive advantage of Canadian crude is evident.

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[33] The Edmonton Journal, June 27, 1970, p. 1. A $1.5 billion natural gas pipeline, operating by mid-1974 between Alaska and Alberta was proposed.

[34] Foster Associates of Washington, D.C., and Foster Economic Consultants, Calgary, Prospective Demand for Canadian Crude Oil under Alternative Industry and Canadian-United States Government Policies, (Calgary, October, 1969), Chapter XII, p. 22.

Table 18 - Laid Down Cost of Crude (U.S. $/bl.)

Source	(a) At St. Louis		(b) At Philadelphia (District I)	
	Alberta	U.S. Gulf	Alberta	U.S. Gulf
Wellhead price	2.61	3.42	2.61	3.42
Transportation	.43	.32	.60	.59
Duty	.11	-	.11	-
Laid down cost	3.15	3.74	3.32	4.01

Source: Foster Associates, op. cit., Table XII-XXII.

Conclusion

Canada can become an economically stronger nation through expansion and diversification of markets IF price reductions are carried out. Until this is accomplished, Canada will be forced to be content with American markets that are determined by and large by political considerations and the international oil cartel in which we have no part. Therefore, the following chapter considers the scope for reductions in the price of Canadian crude.

CHAPTER IV

THE SCOPE FOR REDUCTIONS IN THE PRICE OF CANADIAN CRUDE

The laid-down price of Canadian crude in any market consists of the wellhead price plus transportation costs. The discussion in this chapter will consider whether downward revisions in either or both of these components are possible. The scope for wellhead price reductions in both conventional and synthetic production will be considered first, and will comprise the bulk of the discussion. Subsequently, the scope for pipeline tariff reductions will be briefly examined.

Wellhead Price Reductions

Wellhead Price Reductions in the Conventional Crude Industry

The Objectives of Prorationing

The objectives of prorationing are twofold, to minimize physical waste both above and below ground.[1] The former

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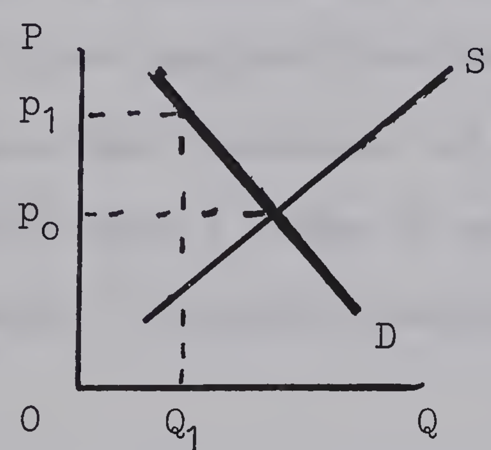
[1] Stella Thompson, "Prorationing of Oil in Alberta and Some Economic Implications," (unpublished M.A. thesis, University of Alberta, Fall, 1968), pp. 95-96.

is accomplished by engineering allowables or good engineering practices; the latter by equating supply and demand. Good engineering practices are necessitated by high initial investment which must be committed at zero output. Therefore, if price more than covers operating costs, producers possess a powerful financial incentive to extract crude as rapidly as possible. Moreover, because of oil's fugaceous nature and because of the "checkerboard" ownership of pools, producers may feel the best plan of operation - under the rule of capture - involves the most rapid withdrawal of crude, even though such action may affect the volume of oil that may ultimately be recovered from that pool. Thus, purely on the basis of physical conservation principles a strong case can be made for proration policies.

For our purposes, the second objective of prorationing - price stability - is more interesting. Prorationing truly stabilizes prices since supplies are altered monthly on the basis of estimated market demand. Hence the basic cause of price instability - the imbalance between supply and demand - is all but eliminated. The basic element missing from this arrangement is price. Estimates are made of how much of the potential production of a province will find purchasers at a price, and the price is the current or prevailing price.[2] This amount is then

[2]Wallace F. Lovejoy and Paul T. Homan, Economic Aspects

allocated among the provinces' producers. "No estimate is made of 'demand' in the sense in which that word is used in economic theory: a schedule of quantities that buyers will take at various prices."[3] The provincial authorities estimate the amount demanded at a given point on the demand curve, taking as given the current level and structure of prices. Assume p_1 is the price announced by the government conservation authorities and that p_o is the price at which the market would be cleared.



But at p_1, OQ_1 is the amount demanded, and this is the amount prorated by the authorities among fields and wells. Thus, prorationing prevents the prevailing overcapacity from underming the price structure. As the excess capacity developed, the prorationing system acted as a ratchet, by which when prices had risen, they were prevented from falling. This was accomplished by severe restrictions on the more prolific wells

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<u>of Oil Conservation Regulation</u>, (Baltimore: John Hopkins Press, 1967), p. 239.

[3] <u>Ibid</u>.

with quotas related to such variables as capacity, depth and spacing. On the other hand, the usual practice involved no restrictions on marginal wells.

For two reasons, prorationing has maintained prices at levels higher than those that would exist in its absence. Firstly, high cost wells are not driven from the industry. In many cases, their revenues may exceed their operating and maintenance costs. In other cases, a normal return on past sunk investment is not required since the original investment may have long since been recovered. As a result, there are more marginal wells under a system of market demand proration than under a system of competitive extraction with or without unitization.[4]

Secondly, prorationing induces cost distortions.

> Lifting costs are proportional to the number of wells in operation, rather than to the number of barrels produced. Since prorationing usually operates by reducing output per well, rather than the number of wells in operation, it does not reduce total lifting costs but increases cost per barrel.[5]

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[4]Nabil T. Khoury, "Prorationing and the Economic Efficiency of Crude Oil Production," Canadian Journal of Economics, II, (August, 1969), p. 447.

[5]Dave Quirin, op. cit., Chapter 6, p. 54.

Furthermore, under earlier policies, the allowables were seldom made proportionate to the size of the spacing unit, hence operators drilled intensively in an effort to obtain increased allowables. As a result of this overdrilling, costs have been raised substantially. Quirin estimated that during the years from 1951 to 1964, there was a waste of $929.9 thousand (due to overdrilling) that could have been avoided with 320 acre spacing.[6] Hopefully, the new Alberta prorationing scheme with allocations based on reserves, will remove much of the incentive to overdevelop. In conclusion, the proration system is beset by elements of economic inefficiency. Inefficient marginal wells are not forced from the industry; efficient wells are subject to less than the optimum rate of output.

The Solutions

As Khoury states:

> From a purely economic viewpoint - ignoring all other considerations . . . the competitive extraction with field unitization system seems to provide the most efficient allocation of resources . . . under this system there will be fewer extra marginal wells and the price of oil will tend to be lower than under a market proration system.[7]

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[6] *Ibid.*, p. 47.

[7] Nabil T. Khoury, *op. cit.*, p. 447.

In addition, this system would be superior to competitive extraction without unitization, since wasteful production associated with the rule of capture would be avoided. The most obvious objection to any form of competitive extraction is the instability generated in the market for crude oil.[8] Prices will be ultra-sensitive to "tapping of new reserves and improvements in extraction techniques."[9]

Obviously, the solution lies in policies that retain

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[8]Thompson's interpretation (Thompson, op. cit., p. 86) of the situation is the following:

> If it is assumed that the only limitations on production are those set according to a pool's MPR and that there is an over-supply situation similar to the one which presently exists, it seems likely that the immediate effect of the removal of prorationing would be a sharp decline in prices. Unless the decline were checked by inter-company fixing of prices, prices would fall to levels unrelated to the costs of producing the oil and, more important, unrelated to the costs of finding oil to replace the reserves that are consumed. The result would be that many companies would have to cease operations and the investment funds needed for exploration (to replace the reserves consumed) would be redirected to other more stable and more profitable industries. Productive capacity would decline until the supply equalled demand or fell below it. In such a situation of scarce oil it is difficult to estimate what the price would be.

[9]Nabil T. Khoury, op. cit., p. 447.

the virtues of prorationing but which remove the elements that harbour the inefficiencies. As it stands, some form of prorationing is needed to achieve price stability. Although Alberta law provides for unitization under certain circumstances, it is not widely practiced. However, there does not appear to be any insurmountable legal obstacles involved in implementing a system of unitization with prorationing, between pools. Nevertheless, if checkerboard ownership remains the rule, other remedies will be required to remove the inefficiencies.

Khoury suggest the establishment of market quotas while retaining the current prorationing system. He envisions that the quotas would become transferable in a market that would develop as a result of the difference in productivity between stripper and non-stripper wells.[10]

> Owners of productive wells would then find it profitable to buy stripper quotas. It is even conceivable that operators of productive wells would "buy out" strippers for the equivalent of the present value of all future quotas that would have accrued to them for their remaining reserves.[11]

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[10] For our purposes the terms marginal well and stripper well will be synonomous. They will be used to describe wells of small and settled production.

[11] Nabil T. Khoury, op. cit., p. 448

The extinction of marginal wells would thus be brought about by this new market. Productive wells would now produce the same total volume of oil as when the strippers were operational, but with greater economic efficiency. Hence, there would be scope for price reductions.

Two problems are apparent in this policy. Firstly, to prevent any one stripper still operating in the pool from gaining access to the reserves of the entire reservoir, all stripper quotas in a common reservoir would need to be sold and the wells shut down. Secondly, with the sale of their quotas, the marginal wells would be capped, and in Khoury's opinion, "for all intents and purposes, their reserves become unrecoverable in the future."[12] To avoid such waste he suggests that "ownership of stripper reserves in every pool could be concentrated in one entity. In this way the reserves could then be recovered efficiently should the need arise in the future."[13] A more obvious solution would involve wider spacing of producing

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[12]Khoury explained that the salty subsurface water would deteriorate the well casing. If the well was capped for a long enough period (as little as five years), the only way to capture the remaining oil (in Khoury's opinion) would be through drilling and operating a new well. Considering the limited amount of oil left underground in the case of stripper wells, this would be uneconomic.

[13]Nabil T. Khoury, op. cit., p. 448.

wells. After the marginal wells were closed, with 320 acre spacing, the oil would flow to areas surrounding the producing wells.

Other policies have been suggested to remove inefficient wells from production. Perhaps marginal wells should only be allowed to operate until costs are recovered. In order to stimulate exploration, there should be some promise of generous production from newly discovered sources. To allow this might require a dual system of allocation. New reservoirs could be allowed production at a relatively generous percentage of maximum efficient rate or of reserves, while old wells could be retained with their allowances cut to permit allocations to new reservoirs.[14] In short, Canada must exploit her richer fields in much the same manner as she has turned to develop her richer copper mines and her lower-cost forest.[15]

The Supply of Conventional Crude Forthcoming at Lower Wellhead Prices

Quirin observed that Canada's share of capacity in highly productive fields exceeded by far her share in total capacity. In Alberta alone, over 91 per cent of capacity had

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[14]W.F. Lovejoy, and Paul T. Homan, op. cit., p. 283.

[15]Anthony Scott, op. cit., p. 275.

per well production potential of more than 100 b/d. Whereas Canada's production capacity amounted to 16.4 per cent of the North American total, her share in capacities over 50, 100 and 200 b/d were respectively 25.7 per cent, 34.5 per cent, and 41.5 per cent. From these figures it can be readily understood that Canada in general and Alberta in particular bears an undue proportion of the brunt of production cutbacks due to prorationing.[16]

Utilizing these estimates of North American productive capacity, Quirin attempted to find the supply of crude forthcoming at various prices in the short run. He assumed marginal wells would still produce if revenues exceeded operating costs plus royalties. Because lifting costs fall rapidly as production is increased with sizeable shut-in capacity, substantial price cuts would be necessary to result in a large reduction in capacity. Table 19 outlines his cost estimates:

Table 19 - Lifting Costs at Different Rates of Production.

Production rate (b/d)	Lifting cost/bl. (U.S. $)
5	2.47
22	.60
50	.26
75	.18
100	.13
200	.07

Source: Dave Quirin, *op. cit.*, Chapter 4, p. 27.

[16] D. Quirin, *op. cit.*, Chapter 4, p. 24.

It would seem that the costs of conservation policies (which are responsible for maintaining marginal fields) is large in relation to the incremental capacity generated by maintaining the price above the market-clearing level.

The short run estimates, although very approximate, are presented in Table 20. With only M.E.R. restrictions on output, North American fields would have produced 12.6 million b/d at crude prices prevailing in 1965. At $1.80, 12.1 million b/d would have been produced and at $1.40, 11.49 million b/d. At the 1965 price, Canada would have produced 2.07 million b/d, which would have been .83 million b/d more than necessary for self-sufficiency.

Utilizing the estimates in Table 20 and by making assumptions concerning the rate of both depletion and growth in reserves, Quirin predicted the supply of crude available at various prices in 1975. He heroically assumed continuing exploration at CURRENT levels with results similar to those experienced historically.[17] A further assumption was that

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[17]At first thought, this assumption may be disputed. However, price reductions need not necessarily occur at the expense of profits. Hence price reductions need not reduce the attractiveness of investment in the oil industry, and therefore would not necessarily mean reduced exploration.

Table 20 - A Supply of Crude Oil at Various Wellhead Prices, 1965 (Thousand b/d).

	.20	.40	.60	.80	1.00	1.20	1.40	1.60	1.80	2.00	Present Price
Total U.S.	3,915	6,260	7,335	8,170	8,925	9,235	9,478	9,722	10,077	10,323	10,534
Canada											
Alberta	1,680	1,730	1,760	1,765	1,770	1,771	1,772	1,774	1,776	1,778	1,780
Saskatchewan	92	138	170	177	183	185	187	190	193	196	200
Other	20	48	52	55	58	60	62	64	66	70	70
Total Canada	1,792	1,916	1,982	1,997	2,031	2,016	2,021	2,028	2,035	2,044	2,070
TOTAL	5,707	8,176	9,317	10,167	10,956	11,251	11,499	11,750	12,112	12,367	12,604

Source: Dave Quirin, op. cit., Chapter 4, p. 29.

there would not be any further discoveries of the magnitude of Prudhoe Bay in the 1970's. Even though such are possible, they could not be marketed until the late 1970's at the earliest. Alaskan production in 1975 was assumed to be 2,000,000 b/d. The volumes presented in Table 21 were obtained by multiplying the 1965 estimates by the projected reserves change. At lower prices, output is less than at higher prices. However, substantial price reductions only alter Canadian output marginally, and at lower prices, the volumes produced would exceed the volumes currently produced. Even at a price of $.40/bl. Canadian production would be around 900,000 b/d greater than the National Energy Boards projected demand of 1,678,000 b/d.

Table 21 - Projected Supplies of Crude Oil Available at Various Wellhead Prices, 1975 ($ U.S. per Barrel, 000 B/D)

	.40	.80	1.20	1.60	2.00	Maximum
U.S.	8,685	10,665	11,725	12,148	12,630	12,950
Canada	2,580	2,700	2,720	2,740	2,770	2,800
Total	11,265	13,365	14,445	14,888	15,400	15,750

Source: Dave Quirin, op. cit., Chapter 4, p. 36.

Wellhead Price Reductions in the Synthetic Crude Industry

The Background of Tarsand Development

Alberta' oil sands which were discovered by explorers in 1778, are deposits of sand containing crude bitumen, a viscous hydrocarbon. Because the sand grains are wet with oil, and because there is insufficient drive to permit production by conventional techniques, the sand is mined by huge electric digging wheels.[18] Overburden must be removed before the 130 foot deep sand deposits can be reached. This limits exploration by mining to deposits within 250 feet of the surface, and would involve only 64.8 billion barrels of conventional oil equivalent, i.e. approximately 20 per cent of attainable tar sand reserves.[19] Total reserve estimates are staggering. All Alberta deposits were estimated to be 710.8 billion barrels, but of this amount, only 415.8 billion barrels were deemed to be recoverable heavy oil, i.e. equivalent to about 300.9 billion barrels of conventional crude. The magnitude of oil sand reserves

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[18]Alternate methods have been proposed for developing deeper deposits. The drilling of wells and flushing the oil from the sand with steam or water is one method. Underground nuclear explosions have also been considered. Quirin, unlike the U.S. Task Force, sees little hope for cost reduction in these alternate methods.

[19]Dave Quirin, op. cit., Chapter 5, p. 6.

can fully be realized by considering that in 1968 world reserves of conventional crude were estimated to be 509.88 billion barrels.[20]

The Oil Sand operation is more than just an extractive process. Other than mining and extraction, it involves partial refining to upgrade the crude, and transportation to pipeline facilities at Edmonton. The cracking process yields gas and coke (which are utilized as fuels), and liquid hydrocarbons which are subjected to further refining to produce a sulphur-free synthetic crude. An important by-product of the latter process is sulphur.

The first application to the Alberta Oil and Gas Conservation Board was filed in 1960 by Great Canadian Oil Sands Limited. Their proposal to establish a 31,400 b/d plant was rejected primarily because of its feared impact on the conventional crude market. However, final judgment of the application was deferred until 1962, and after re-hearing the proposal, the Board consented to the development. In 1963, because of difficulty in financing a project of this size, the company requested and received approval to increase its allowed daily output to 45,000 barrels.

The policy of the Alberta government was, in short, to allow synthetic crude production to supplement but not to supplant

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[20] World Petroleum Review, 1969, p. 25.

conventional crude production. The reason for this policy was that the conventional crude and natural gas industries had substantial expansive effects on the Alberta economy, having virtually doubled the province's economy since 1947.[21] To allow synthetic production unlimited access to the market could, in view of the overwhelming tar sand reserves, completely collapse the discovery and exploration aspects of the conventional industry. Moreover, in 1969, the industry provided the Alberta government with $276,623,000 in revenue from royalties, rentals, and land sales, an amount equal to 40 per cent of total public revenue.[22] Complicating the issue was the fact that tar sand oil cannot be prorationed since a constant plant througput is essential to make development economically feasible. Initially, synthetic production was to be limited to five per cent of total demand for Alberta oil, but at present the figure is closer to seven per cent. In addition, hydrocarbon products from the oil sands could have been produced without market restriction if the products were destined

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[21] E.J. Hanson, "Stimulate Economic Growth with Petroleum Revenue," Oilweek (March 20, 1967), p. 26.

[22] Calculated from figures from Oilweek (February 23, 1970), p. 90, and Province of Alberta, Public Accounts, 1969.

for markets not currently supplied by conventional Alberta crude. The government also intended to relate the scale and timing of incremental synthetic production to the years of remaining proven supply of conventional crude. Apparently, oil sands development was to be accelerated, if necessary, to maintain the reserve's-life index at a level of 12 - 13 years.[23]

In February, 1968, the Alberta government revised its oil sands development policy. The most important change was a re-defining of the markets that may be served by synthetic crude into the following three categories - "within reach markets, new markets and beyond reach markets."[24] A "new market" was considered to be one not being served today, one over and above

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[23] Official Government Statement, Hon. E.C. Manning, Premier of Alberta, cited in Oil in Canada (October 25, 1962).

[24] Government of the Province of Alberta, Oil Sands Development Policy, February, 1968, cited in Stella Thompson, op. cit., pp. 66-68. This discussion is drawn from Thompson's work, and "New Oil Sands Policy Allows 150,000 b/d Output," Oilweek (February 26, 1968), pp. 15-16.

the normal growth in existing markets or one representing a net increase in the total market. Until 1973, up to a total of 150,000 b/d of synthetic crude can be sold in these within reach and new markets. However, the "new markets" would be split equally between conventional and synthetic production. This practice was intended to spur synthetic producers to search for new markets and at the same time to provide the conventional industry with some of the benefits of the new markets. "Beyond reach markets," defined to be those markets which Alberta's conventional industry are not at present serving (nor will serve in the foreseeable future) for reasons of price or quality, were not restricted.

The Possibility of Wellhead Price Reductions in Synthetic Production

Quirin estimated the long run average cost per barrel of synthetic crude, and found that production on a scale of 45,000 b/d is economically competitive with 34° Redwater if a quality differential is allowed. His example cites synthetic crude laid down at Edmonton for \$2.83/bl. versus \$2.80 bl. for conventional crude. It should be realized that this competitive position depends upon the high North American price structure, and therefore synthetic crude is effectively limited to the same North American markets served by conventional Alberta crude. In view of the

excess capacity now existing in Alberta, "the decision to permit development can only be justified on the assumption that more spectacular results will follow, making possible the securing of additional markets."[25] Such developments would require a reduction in the price of synthetically produced crude.[26]

Development thus far has been committed to the perfection of the mining technology, and therefore it seems likely that any price reductions will stem from economies of scale

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[25]Dave Quirin, op. cit., Chapter 5, p. 12.

[26]In retrospect, the problems experienced by the Oil sands development render such hopes as very optimistic. The 1969 operations lost $25,000,000 and government relief in the form of waived royalties was arranged in early 1970. However, the loss for the first six months of 1970 will be around $9,000,000 versus more than $16,000,000 in the similar 1969 period. Production for the first half of 1970 was 50 per cent above the comparable 1969 period, and three and one-half times that of the comparable 1968 period. How long these losses will be accepted depends upon the company's desire to perfect the process, gain operating experience, and get a foot in the door. The Alberta government also has a strong vested interest. Postponment of oil sands development may enable the United States to perfect oil shale recovery processes, eliminating the immediate need for oil sands production.

rather than technological breakthrough.[27] Quirin calculated costs and operating expenses for three huge integrated plants, with economies of scale anticipated in pipelining, refining, and power plant operations. Beyond a capacity of 400,000 barrels per calendar day (B.P.C.D.), he felt the diseconomies would outweigh the economies. He also judged that with operating experience, costs could be reduced a further 10 per cent by "bottleneck" removal.

Table 22 - Projected Costs of Producing Tar Sands Oil

Scale of Operation	Cost per Barrel
100,000 B.P.C.D.	$2.30
200,000 "	2.03
400,000 "	1.86

Source: Dave Quirin, op. cit., Chapter 5, p. 18.

This reasoning led to an estimated supply price of $2.06/bl. with a 100,000 B.P.C.D. plant with a minimum royalty of $.27/bl. Since it is unlikely any plants of capacity greater than 100,000 B.P.C.D. will be in operation long enough to permit price reductions below those prices presented in Table 22, in the 1970's the minimum price for tar sands oil could be $2.06/bl.

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[27] Dave Quirin, op. cit., Chapter 5, p. 13. This discussion is based on his analysis presented in Chapter 5, pp. 13-20.

The American Task Force Estimates

The American Cabinet Task Force on Oil Import Control estimated Canadian production in 1980 at various price levels. Their estimates, presented in Table 23, are predicated on the assumption of unrestricted access to the American market and the consequent abandonment of prorationing in Alberta.

Table 23 - Canadian Production 1980 (Million b/d)

U.S. Price/bl[1]	Netback Canadian Price (U.S. $)[2]	Output	Domestic Consumption	Exports	Imports
3.30	3.19	6.0	2	5	1
3.00	2.89	6.0	2	5	1
2.50	2.39	4.5	2	3	0.5
2.00	1.89	3.5	2	1.5	0.0

[1]For 30 per cent sweet crude at the South Louisiana wellhead.

[2]At Edmonton, assuming the existing tariff of 10.5 cents/bl. and a revised pipeline rate of 38¢/bl. between Chicago and Edmonton.

Source: The Cabinet Task Force on Oil Import Control, George P. Shultz, Chairman, The Oil Import Question - A Report on the Relationship of Oil Imports to National Security, (Washington: February, 1970), p. 45.

The netback price refers to the price received at Edmonton in American dollars. The netback price in the Mackenzie Delta for crude delivered to Chicago would be some 50¢ less; that for

Arctic island crude delivered to the East Coast would be some 75¢ less, while the netback price of Atlantic offshore oil would be approximately 10¢ above that experienced at Edmonton. Production by source would be as follows:

Table 24 - Canadian Production By Source 1980

Output	Known Areas	New Areas	Tar Sands	N.G.L.	Canadian Oil Share in Eastern Canadian Market
6.0	2.5	2.0	1.0	.5	N.A.
4.5	2.5	1.5	0	.5	50%
3.5	1.7	1.3	0	.5	100%

Source: The Cabinet Task Force on Oil Import Control, The Oil Import Question, page 45. Natural gas liquids (N.G.L.) included to allow for greatly expanded sales of natural gas to the United States.

The Task Force was of the opinion that at a Canadian price of $2.90/bl, even modest-sized Arctic reserves and tar sand deposits could be economically developed. A price of $2.40/bl. would not impair conventional production in known areas, but some reduction in Arctic potential is likely at this price. The Task Force felt no tar sands production would be forthcoming, but considering Quirin's estimates, this point could be disputed. With prices at world level, Atlantic potential would be unaffected, but Arctic development would be feasible only for large reserves.

Even at a wellhead price of $1.89/bl, Canada would be self-sufficient in the ABSOLUTE sense, and still have 1.5 million barrels a day to export.

While there is some discrepancy in our estimates of the magnitude of potential price reductions in synthetic production, it can be concluded that there is scope for both significant wellhead price reductions in the conventional crude industry and smaller wellhead price reductions in the synthetic industry.

The Industry's Attitude to Price Cuts

The slightest mention of a price cut evokes cries of despair from the oil industry, which argues that its profit position would be adversely affected. In turn, the incentive to explore and develop new reserves would be retarded. The Imperial Oil submission to the Royal Commission on Energy stated that the 7 - 12% return the industry was receiving on risk capital was quite modest, and was no more than sufficient to attract new money at normal success ratios.[28] Furthermore, it has been argued that any lower rate of return induced by price reductions would be disastrous for small operators who depend upon debt finance.

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[28] Imperial Oil Limited, Submission to the Royal Commission on Energy, page 10.

This line of reasoning ignores several issues. Firstly, a price reduction should open up more markets to Canadian crude. Thus, the increased volume could result in greater total revenues and/or a shorter well life, hence either the same total return could be achieved in a shorter period, or a greater return could be achieved in the same period. If the former alternative were chosen, the oil companies would have their capital tied up for a shorter period of time. For example, if the life of a well was now 7.5 years instead of 15 years, the company could earn $x in one-half the time, and would be able to re-invest the $x and reap additional earnings for 7.5 years. Secondly, a price reduction would mean a direct loss to those marginal wells already producing at capacity. Since these wells could not increase output to benefit from a price decrease, their earnings would be diminished, leaving the more prolific and efficient wells as more attractive investments. The reasoning behind this is that (a) the initial price reduction would mean an increase in volume for the industry and (b) if the marginal wells could not increase volume to compensate for the price reduction, their production allocations would be transferred to the more productive wells whose volume would then be increased by more than the initial volume change induced by the price cut. Finally, the

integrated companies could balance off the loss from lower after-tax revenues at the producing stage with the gain from lower cost crude.

Nevertheless, voluntary reductions in the wellhead price of crude seem unlikely. A recent study expressed the opinion that "a 13 per cent return would . . . constitute the minimum return requirement which . . . would attract adequate capital to assure development of Canadian resources."[29] It is legitimate to ask how this criterion of adequacy was arrived at. This criterion was based on the "high" risks in the petroleum industry and the recently experienced American 12 - 13 per cent rate of return. However, this reasoning raises some interesting questions. It is a debatable question whether the 7.1 - 8.7 per cent earned in Canada by integrated petroleum companies and the 8.8 - 10.1 per cent earned by independent oil and gas producers (in the 1962-68 period)[30] have failed to provide an adequate supply of capital for the development of Canadian petroleum resources. Finally, to base a Canadian rate of return on that earned in the United States ignores some important considerations. The Amer-

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[29] Foster Associates, op. cit., Chapter VIII, p. 18.

[30] Ibid., p. 9.

ican petroleum industry in 1966 earned a better rate on its domestic operations than on its foreign operations,[31] primarily due to the high wellhead price maintained by the American import restriction program.

Therefore, in the first place, the American rate of return on which the Foster study bases its adequacy concept, is artificially high. Reductio ad absurdum, this argument would suggest that, in line with purely economic considerations, the companies would cease to invest in foreign operations. Secondly, considering the drastic supply shortage facing the United States and the abundance and the advantages of Canadian supplies, it is felt that investment in Canadian petroleum resources will remain attractive.

The Foster study concluded that production would need to be increased substantially to achieve this "adequate" rate of return. They estimated that under co-ordinated American-Canadian policies, a rate of return in excess of 13 per cent would not be attained until 1973 when annual production would hit 614 MM barrels.[32] If currently existing policies were maintained, the study estimated that 1973 production would be 493 MM

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[31] "See Swing to U.S. Domestic Investment," Oilweek (July 17, 1967), p. 11.

[32] Foster Associates, op. cit., table IX-2

barrels, some 121 MM barrels less than under co-ordinated policies. However, in view of the fact that the consumption of petroleum products in Quebec was 124 MM barrels in 1966,[33] it appears that if the Quebec market were to be served by western Canadian crude, then the volume necessary (assuming the Foster Study to be correct) to ensure a 13 per cent plus return in 1973 would be exceeded by a fair margin. Therefore, would there not be a possibility of a price reduction?

Finally, the Levy Study supports the contention that prices could be reduced without economic loss to the industry.

> An increase in production of 200,000 barrels per day, or 25 per cent would mean that average crude prices could be around 22 cents per barrel lower without any reduction in the present discounted value of the industry's future production or in the present value of reserves taking a 5 per cent discount factor.[34]

While it is realized that this discount rate is low, there would still be (even if we discounted by current rates) scope for smaller price reductions if production were expanded by 200,000

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[33] National Energy Board, Energy Supply and Demand Balances, 1955-67, Consolidation of Historical Data, (Ottawa: 1968), Appendix A.

[34] W.J. Levy Inc., The Outlook for Canadian Crude Production and Markets, (New York: October, 1966), Chapter III, p. 14. Unfortunately, the study does not specify if the calculations considered increased production and lifting costs as output was expanded.

b/d. Moreover, a price reduction could expand Canadian sales, and production could be increased by more than 200,000 b/d, thus further enhancing the prospects for price reduction without loss to the industry.

The Scope for Reduction in Pipeline Tariffs

According to current estimates, pipeline tariffs would comprise 20.4 per cent of the total cost of western Canadian crude laid-down in Montreal. If transportation costs could be reduced, the competitive disadvantage of Canadian crude would be lessened. The Levy Study supports this hypothesis

> The lowest rate for the long haul via Interprovincial now works out at around 2.7 cents per hundred-barrel-miles. A modern pipeline system might be able to carry large volumes over long distances at perhaps 2.0 cents per hundred-barrel-miles, or less.[35]

Furthermore, the Levy Study predicted that with substantial volumes of Canadian crude were moved to Montreal, the total transportation cost might be reduced by thirteen cents. This prediction is in line with a more recent prediction cited in the Foster study. The latter group felt that transportation costs to Montreal could be lowered to 50 cents per barrel,[36]

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[35] *Ibid.*

[36] Foster Associates, *op. cit.*, Table XI-4.

some 17 cents less than the current transportation costs quoted by the Alberta Oil and Gas Conservation Board.[37] By coupling wellhead price reductions with tariff reductions, further telescoping of pipeline tariffs would be feasible, and thus "the delivered cost to intermediate refiners would not go up while the delivered cost over the long haul would be minimized."[38]

If Canadian production is dramatically increased and if this increased production is to be moved across Canada to either (or both) Montreal or American markets, plans should be laid for the construction of a large capacity line that would provide the lowest cost of transportation. An interesting possibility is a government-owned pipeline much in the nature of a public utility. Such a line could be justified on the grounds of the national interest if it could expand Canada's exports and reduce her dependence on imports. Special financing considerations available to the government - for example, abnormally low depreciation and income tax concessions - could provide the economic basis for lower transportation costs.

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[37] The Oil and Gas Conservation Board of Alberta, Alberta Crude Oil Competitive Position, (Calgary: November 15, 1969).

[38] W.J. Levy Inc., op. cit., Chapter III, p. 14.

Lastly, a comparison of Interprovincial Pipeline tariffs with American long distance rates reveals that Canadian rates may be excessive.

> Despite considerable variation, the tariff rates per 100 barrel-miles shown for U.S. pipelines are generally well below comparable rates for Interprovincial. For example, two lines from West Texas to Chicago, a distance of about 1,200 miles, quote tariffs which work out to 2.2 - 2.3 cents per hundred barrel-miles. This compares with the lowest rate on Interprovincial of 2.7 cents per 100 barrel-miles for the 1,900 mile haul from Edmonton to Toronto.[39]

On the surface, reductions in Interprovincial tariffs appear possible. Unfortunately, the Levy study does not state whether the rates were for lines directly comparable in terms of diameter, throughput, construction costs, methods of finance and the like. These questions need to be answered before any conclusions can be drawn.

Conclusion

Wellhead price reductions do appear feasible, especially if production was expanded. However, it is very doubtful that the industry would voluntarily introduce significant wellhead price cuts. Therfore, if price reductions are in the national interest, government intervention may be warranted.

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[39] Ibid. Appendix F, p. 5.

Because of prorationing procedures and small well spacing, Canadian output is substantially less than economically attainable. Even with drastic price cuts there would have been ample capacity to meet Canadian demands. Therefore, the importation of foreign crude into Canada does not reflect the inability of Canadian crude to compete, but rather reflects the "normal response to a situation in which prices in a market have been maintained in excess of a competitive level by artificial means."[40]

Finally, the evidence on pipeline tariffs is much less definitive, and thus this question should be examined in greater detail.

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[40] Dave Quirin, op. cit., Chapter 4, p. 32.

CHAPTER V

CONCLUSIONS

The last two decades have witnessed the expansion of the Canadian petroleum industry from an industry of negligible size to the most important mineral producing industry in Canada. Of prime importance in this impressive growth was the National Oil Policy which rescued the industry from its state of despair in 1961 and which, for eight years, sustained a healthy and vigorous producing industry. Unfortunately, recent events have revealed that the National Oil Policy has become unworkable, and a thorough revision of Canada's petroleum policy is urgently required. At present impending policy decisions in both Canada and the United States cloud the market outlook of the Canadian petroleum industry.

Nevertheless, from the discussion presented in previous chapters it has become evident that:

(1) Canada has abundant oil reserves and large excess capacity in her oil industry.

(2) The United States faces a drastic shortage of all forms of energy, including oil and especially

natural gas.

(3) Canadian crude is more than competitive with U.S. domestic crude in some American markets. With price alterations Canadian crude would become competitive in more distant market areas of the U.S.

(4) Canadian crude offers the security of overland supply.

Obviously, the two countries could mutually benefit from the co-ordination of oil and gas development and import policies. Canada would increase production significantly[1] and reap the associated benefits in other sectors of the economy.[2] The

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[1]In the April 14 edition of the Edmonton Journal (p. 15) Dome petroleum predicted that with integrated policies, in 1980 oil production would be 3,600 MM b/d, natural gas production 10,800 MM cubic feet per day and N.G.L. production 240,000 b/d. Similarly the Foster study (tables XII-1 and XII-9) predicted that exports to the U.S. would be 1,644 M b/d in 1978 whereas with existing policies they would be 1,607 M b/d in 1983.

[2]Glenn Nielson, chairman of Husky Oil estimated that increased oil and gas exports to the United States and the sale of western Canada oil in Montreal would add more than $1 billion to Canada's G.N.P. by 1973, and $1.25 billion by 1975. (cited in Oilweek (June 23, 1969), p. 28.)

United States could reduce her crude costs and at the same time avoid a precipitous decline in American crude prices that would accompany the removal of import restrictions. Both would benefit from having a secure supply source with enough excess capacity to cover an emergency cut-off of offshore supplies.

While there are certain benefits to integrated oil and gas trade policies, there are two issues that need to be considered. Firstly, joint Canadian-American oil policies have become lumped under the title of "continental energy policies," a phrase that has evoked emotional disapproval in Canada because it bears connotations that Canadian development, sovereignty, and self-determination may become secondary to continental policy. This situation could be prevented by avoiding "blanket" energy proposals. Without weakening her bargaining position, Canada can attain the aforementioned benefits within the context of integrated oil and gas trade policies rather than by entering a complex all-encompassing energy pact. It cannot be overemphasized that (1) United States desperately requires our oil and gas and (2) Canada possesses the trump card in negotiations - her right to grant pipeline and/or water access to northern discoveries. With firm leadership, Canada can maximize the benefits accruing to Canadians and minimize the threat to Canadian sovereignty.

The second issue involves pollution and the development of Canada's delicate Arctic areas. Petroleum operations in the Canadian Arctic, a vital facet of co-ordinated oil and gas policies, could jeopardize the fine ecological balance of the Arctic. The laid-down cost of Arctic crude should reflect the extra costs incurred in preserving the Arctic areas. For example, if high cost above ground pipelines were used, transportation charges would be high.

Regardless of the government's course of action concerning integrated oil and gas trade policies, a third issue, the perennial Montreal market question will have to be considered. If co-ordinated policies are pursued, the U.S. would require Canada to limit her dependence on offshore crude imports, i.e. domestic crude would supply at least part of the Montreal refining market. Without co-ordinated policies, tapping of the Montreal market may be necessary to provide markets for volumes of Canadian crude that are necessary to maintain a healthy domestic industry.

Several policies for laying down Canadian crude competitively in Montreal have been proposed. According to one, the wellhead price of crude to be exported to the United States would be increased in order to offset lower prices for western Canadian crude sold in Montreal. The new price for American exports would still be competitive with indigenous American production. Obviously, the Americans would not agree to a

policy whereby they would subsidize Quebec consumers. A more complicated, but more valid proposal involved the lowering of federal and provincial taxes on each gallon of gasoline sold in Quebec to offset price increases to Quebec consumers. The lost revenues would be compensated for by transfers of revenue from the producing provinces who reaped the benefits of increased production. A one cent reduction in gasoline taxation would cost the federal and Quebec government about $42 million, but would provide "an economic upswing worth about $300 million in taxes."[3] Any price alterations raise the question of whether the same treatment will be afforded to Ontario consumers.

Indeed, it is apparent that the oil industry views wellhead prices as being downwardly rigid, when in fact they merely reflect the artificially high American wellhead prices and the dominance of the international oil cartel. Virtually all the discussion of laying down Canadian crude in Montreal involves subsidies and/or other forms of protection. On the other hand, material presented in Chapter IV suggests that wellhead price reductions are economically feasible and that

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[3]"Billion Dollar Opportunity if Montreal Market Opens," Oilweek (June 23, 1969), p. 28.

an abundant supply of crude would be forthcoming at much lower prices. Therefore, it is concluded that with wellhead price reductions, western Canadian crude can be economically laid-down at Montreal.

In view of the magnitude and gravity of the issues presented in both this chapter and the previous ones, the following items should be subjected to an exhaustive study BEFORE any attempt is made to formulate long-term oil policies for Canada.

(1) Canada should outline what she wants to achieve within the context of an oil policy. Supply should be assured for all of Canada. To do so involves the maintenance of a healthy domestic industry. Therefore, exploration and development of petroleum resources on the prairies <u>and</u> Arctic and offshore areas should be encouraged. Guidelines for Canadian control (or ownership) of future developments should be formulated.

(2) Secondly, an indepth analysis of the pricing structure of Canadian crude should be under-taken and the feasibility and consequences of

abandoning what is, in effect, the North American price structure should be carefully evaluated. Involved in this study would be the effect of implementing a price structure (or structures) which is more closely related to the economics of production.

(3) The third area involves the Montreal market. What would be the optimal volume of western Canadian crude that should be allowed in the market in view of pipeline considerations and the possibility of offshore discoveries on the east coast? What would be the cost of alternate pipeline connections to Montreal and could the flow be readily reversed? Finally, can pipeline tariffs be reduced?

There are no simple solutions to the dilemma facing the Canadian petroleum industry. The issue extends beyond the boundaries of the petroleum industry to include questions of foreign ownership and investment, economic nationalism, pollution control, Arctic sovereignty, and international relations. Hopefully, if the above questions are answered, Canadian policy makers will at least be aware of what they can or cannot do. This would be a marked improvement over the current state of affairs.

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